Hydrocarbon and By-Product Reserves in British Columbia

2013 | BC Oil and Gas Commission

BC Oil & Gas COMMISSION

About the

BC Oil and Gas Commission

The BC Oil and Gas Commission (Commission) is the provincial single-window regulatory agency with responsibilities for regulating oil and gas activities in British Columbia, including exploration, development, pipeline transportation and reclamation.

The Commission's core services include reviewing and assessing applications for industry activity, consulting with First Nations, cooperating with partner agencies, and ensuring industry complies with provincial legislation and all regulatory requirements. The public interest is protected by ensuring public safety, respecting those affected by oil and gas activities, conserving the environment, and ensuring equitable participation in production.

For general information about the Commission, please visit: www.bcogc.ca or phone 250-794-5200.

Mission

We regulate oil and gas activities for the benefit of British Columbians.

We achieve this by:

- Protecting public safety,
- Respecting those affected by oil and gas activities,
- Conserving the environment, and
- Supporting resource development.

Through the active engagement of our stakeholders and partners, we provide fair and timely decisions within our regulatory framework.

We support opportunities for employee growth, recognize individual and group contributions, demonstrate accountability at all levels, and instill pride and confidence in our organization.

We serve with a passion for excellence.

Vision

To provide oil and gas regulatory excellence for British Columbia's changing energy future.

Values

Respectful

Accountable

Effective

Efficient

Responsive

Transparent

Purpose of Report

Hydrocarbon and By-Product Reserves

The oil and gas production and remaining recoverable reserve numbers are a current reflection of the state of development in British Columbia. As drilling continues to define additional prospective lands, resource estimates become proven reserves, substantiated with production volumes and geological data.

This report summarizes oil and gas production and remaining recoverable reserves in British Columbia providing assurance of supply for the development of policy, regulation and investment. It also emphasizes the growth and future potential of unconventional resources as a long-term source of natural gas for the province.

Estimates of British Columbia's natural gas, oil, condensate, and associated by-product reserves as of Dec. 31, 2013 are presented in this report. The estimates have been prepared by the Commission using accepted geological and engineering practices (including the Canadian Oil and Gas Evaluation Handbook (COGEH) and the Guidelines for the Practical Evaluation of Underveloped Reserves in Resource Plays (SPEE Monograph 3)).

The reserve numbers represent proved plus probable (P_{50}) reserves recoverable using current technology. Reserves are proven by drilling, testing and/or production and include proven undeveloped (PUD) reserves interpreted from geological data and/or analogous production.

Table of Contents

Available on the Commission website:

Detailed Gas Reserves By Field and Pool

Detailed Oil Reserves by Field and Pool

Detailed Condensate and By-Product Reserves by Field and Pool

Executive Summary

British Columbia's remaining reserves as of Dec. 31, 2013, together with a comparison of the Dec. 31, 2012 reserves, are summarized in Table 1.

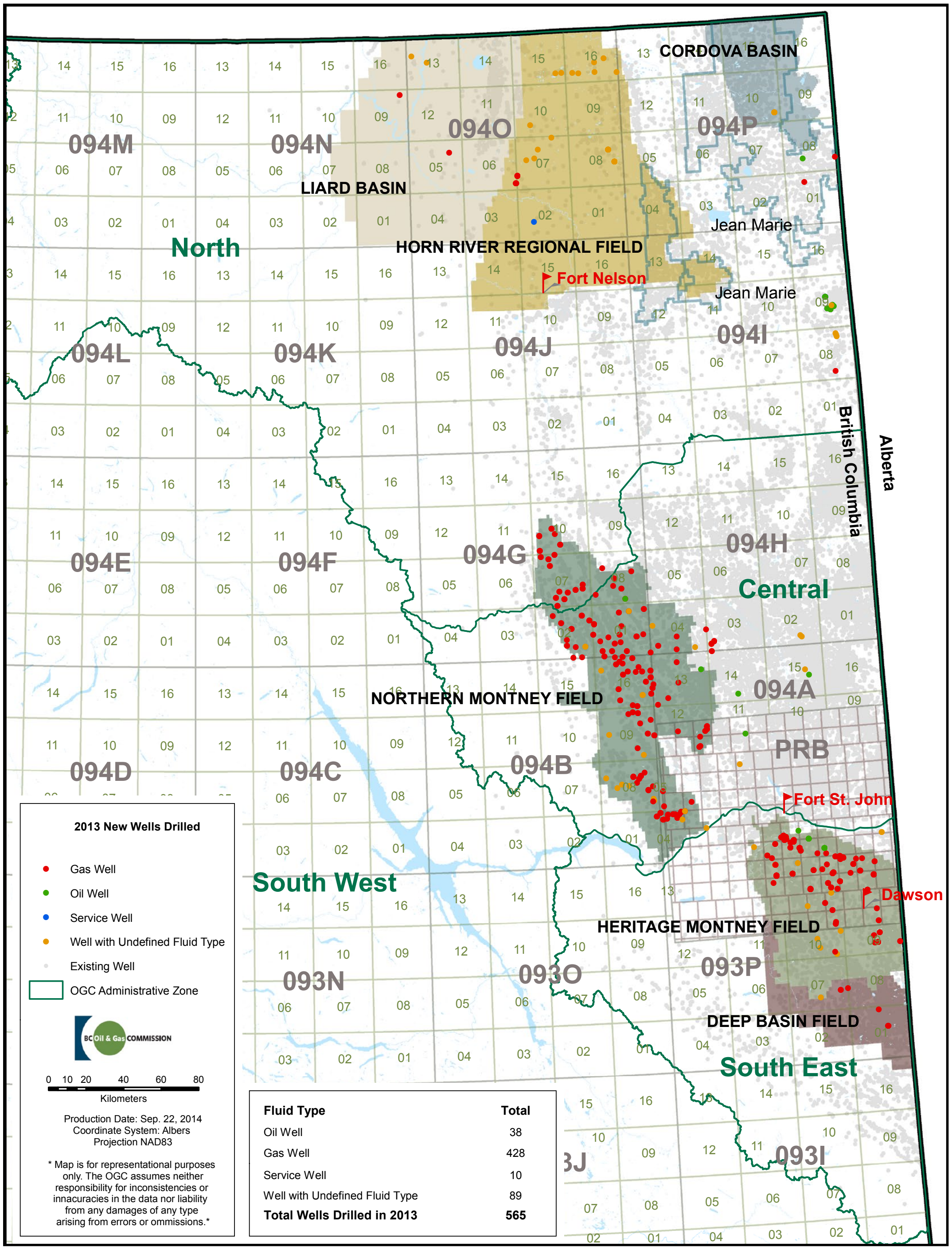
Reserves increased for all products, mainly due to expansion and development of the regional Montney formation, contributing to gas, condensate, natural gas liquids (NGL) and oil production. Unconventional reservoirs have tremendous growth potential, with booked reserves (raw) representing less than two per cent of current resource estimates of 2,900 Tcf OGIP (see Appendix B, Table B-1: Summary of Unconventional Plays).

Detailed information on the reserves and reservoir parameters for each field and pool in B.C. is provided on the Commission website as listed in the Table of Contents on page 3. Historical data from previous hydrocarbon reports published by the Commission is summarized in Appendix A; Tables A-2 and A-3.

Table 1: Remaining Reserves as of December 31, 2013

Reserve Type	2012	2013
Oil	19.1 10^6 m^3 (120.2 MMSTB)	19.3 10^6 m^3 (121.4 MMSTB)
Gas	1,138.5 10^9 m^3 raw (40.2 Tcf raw)	1,197.2 10^9 m^3 raw (42.3 Tcf raw)
Condensate	16.2 10^6 m^3 (101.9 MMSTB)	20.8 10^6 m^3 (130.7 MMSTB)
Natural Gas Liquids	44.0 10^6 m^3 (277.0 MMSTB)	53.6 10^6 m^3 (377.1 MMSTB)
Sulphur	15.7 10^6 tonnes (15.5 MMLT)	17.7 10^6 tonnes (17.4 MMLT)

Figure 1: Wells Rig Released in 2013



Fluid Type	Total
Oil Well	38
Gas Well	428
Service Well	10
Well with Undefined Fluid Type	89
Total Wells Drilled in 2013	**565**

The targeted plays by wells rig released in 2013 is presented in Figure 1, which shows the location and areal extent of the major unconventional fields (Montney, Horn River, Liard, Cordova Embayment, Jean Marie and Deep Basin Cadomin). Of the 457 wells that were drilled targeting the Montney, 60 per cent of these were located in the southern portion of the play (Regional Heritage field) and 40 per cent in the north (Northern Montney field). A recent discovery of an oil leg within the Montney led to the drilling of 16 Montney oil wells in 2013 (42 per cent of total oil wells drilled). The most active area of oil drilling remains the Hay River – Bluesky “A” pool (17 wells; 45 per cent of total oil wells drilled). There were also 11 service wells drilled in 2013, down 27 per cent from 2012, due to a reduction in drilling for source water (one disposal well and nine injection wells). All of the injection wells were drilled to support the Hay River Bluesky “A” pool waterflood.

Figure 2: 2013 Drilling Activity by Play Area

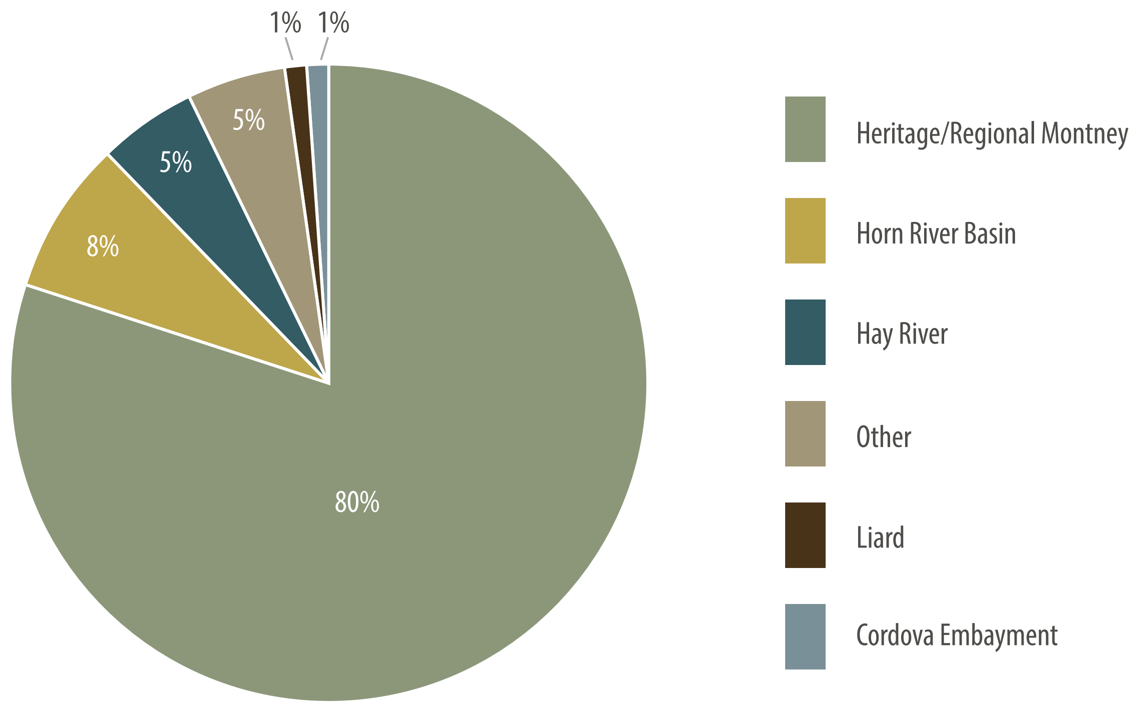


Figure 2 shows the 2013 drilling activity by play area. The Montney was the dominate zone with 80 per cent of the wells drilled in this area compared to 73 per cent in 2012. Significant drilling activity also occurred in the Horn River Basin (HRB) and the Hay River Bluesky "A" oil pool. A total of 565 wells were drilled in B.C. in 2013 compared to 455 wells in 2012[1].

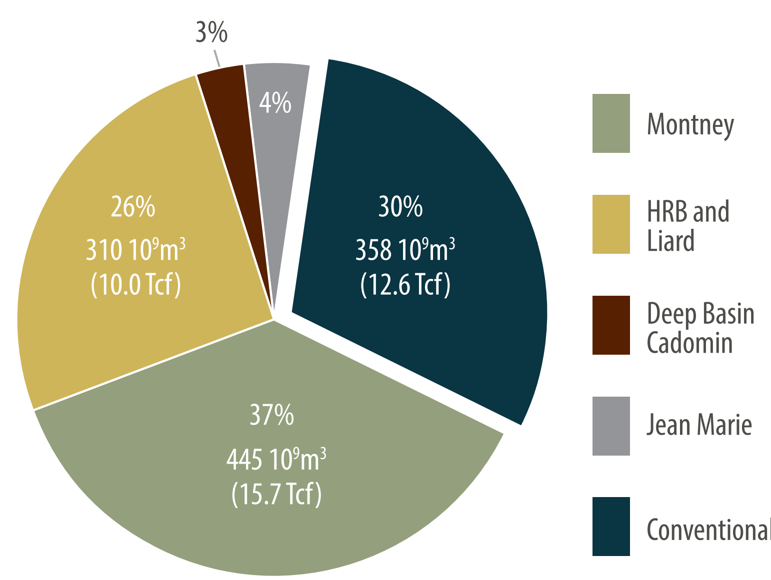
Discussion

A. Gas Reserves

As of Dec. 31, 2013 the province's remaining raw gas reserves were 1,197.2 10^9 m^3, a five per cent increase over the 2012 value. The upward trend of reserve revisions continues largely due to successful development of unconventional Montney tight gas and Horn River shale gas, with continuous improvements in horizontal drilling and hydraulic stimulation technology.

Figure 3 illustrates the distribution of remaining gas reserves per field, with approximately one-third coming from each of the large unconventional plays (Montney and Horn River) and the remaining third from existing conventional reserves. Unconventional sources are expected to further dominate new activity, with continued depletion of conventional pools.

Figure 3: Remaining Gas Reserves - Conventional vs. Unconventional



[1] Variations in drilling numbers may occur due to differing methodologies surrounding initial drilling and re-entry counts. Please contact the Commission with any questions.

The progression from conventional drilling of “high” permeability (1-10 mD) gas reservoirs to “low” permeability (<500 nD) regionally extensive unconventional gas basins is highlighted in Figure 4. The Montney, Horn River, Jean Marie and Deep Basin Cadomin comprise the unconventional production shown in Figure 4, with the remainder combined as conventional. In 2005, the unconventional Deep Basin Cadomin and Jean Marie accounted for 20 per cent of B.C.’s total, with the majority of B.C.’s production coming from conventional gas wells.

In 2011/2012, for the first time, unconventional production surpassed that of conventional production. Currently, unconventional plays account for 67 per cent of B.C.’s total gas production. Conventional production is declining at eight per cent per year with minimal drilling having taken place in 2012/2013. Total natural gas production for 2013 was 43.7 10^9m^3 (1.5 Tcf), an eight per cent increase over 2012 annual production.

Figure 4: Gas Wells Drilled Per Year and Calendar Day Raw Gas Rate

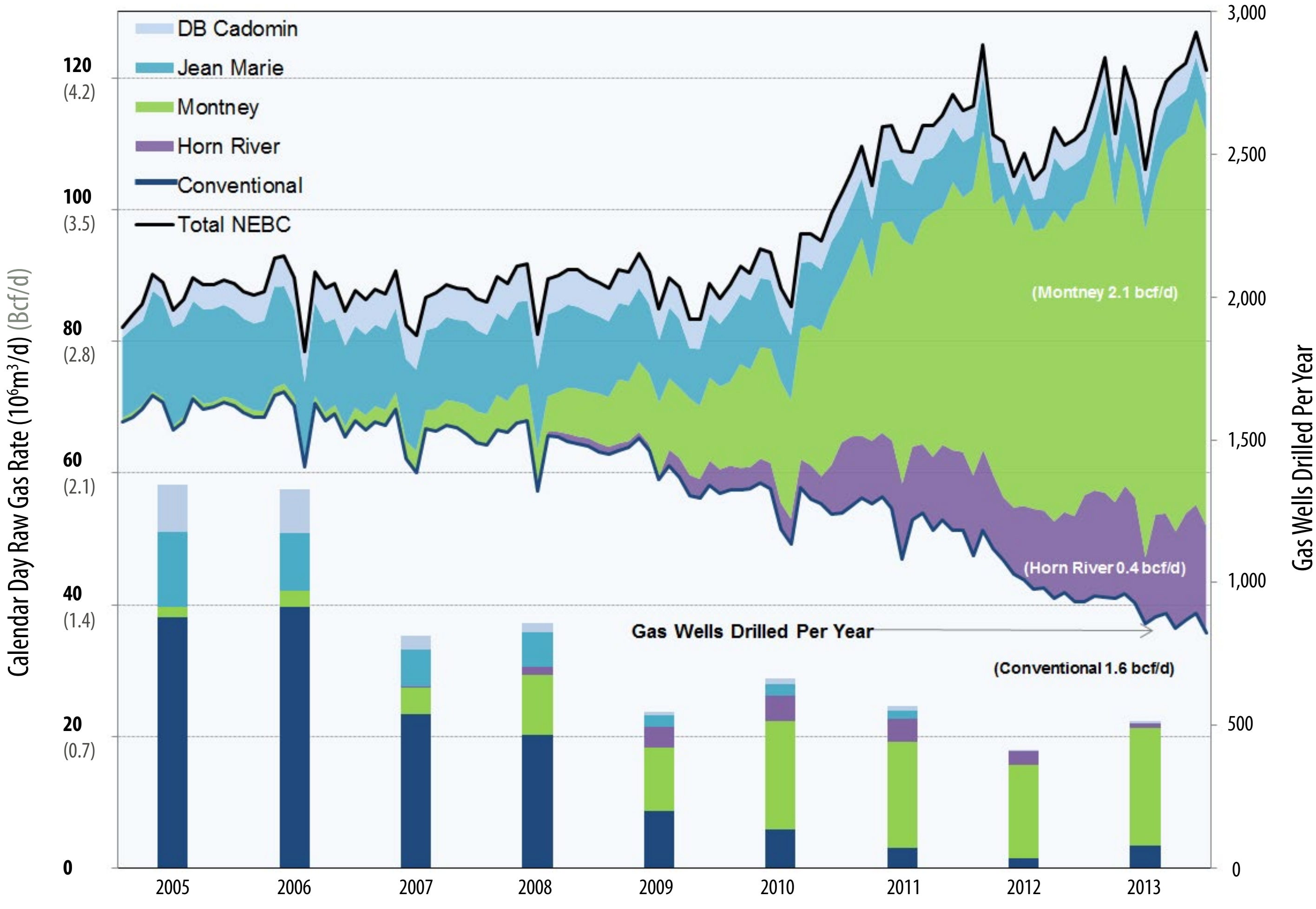
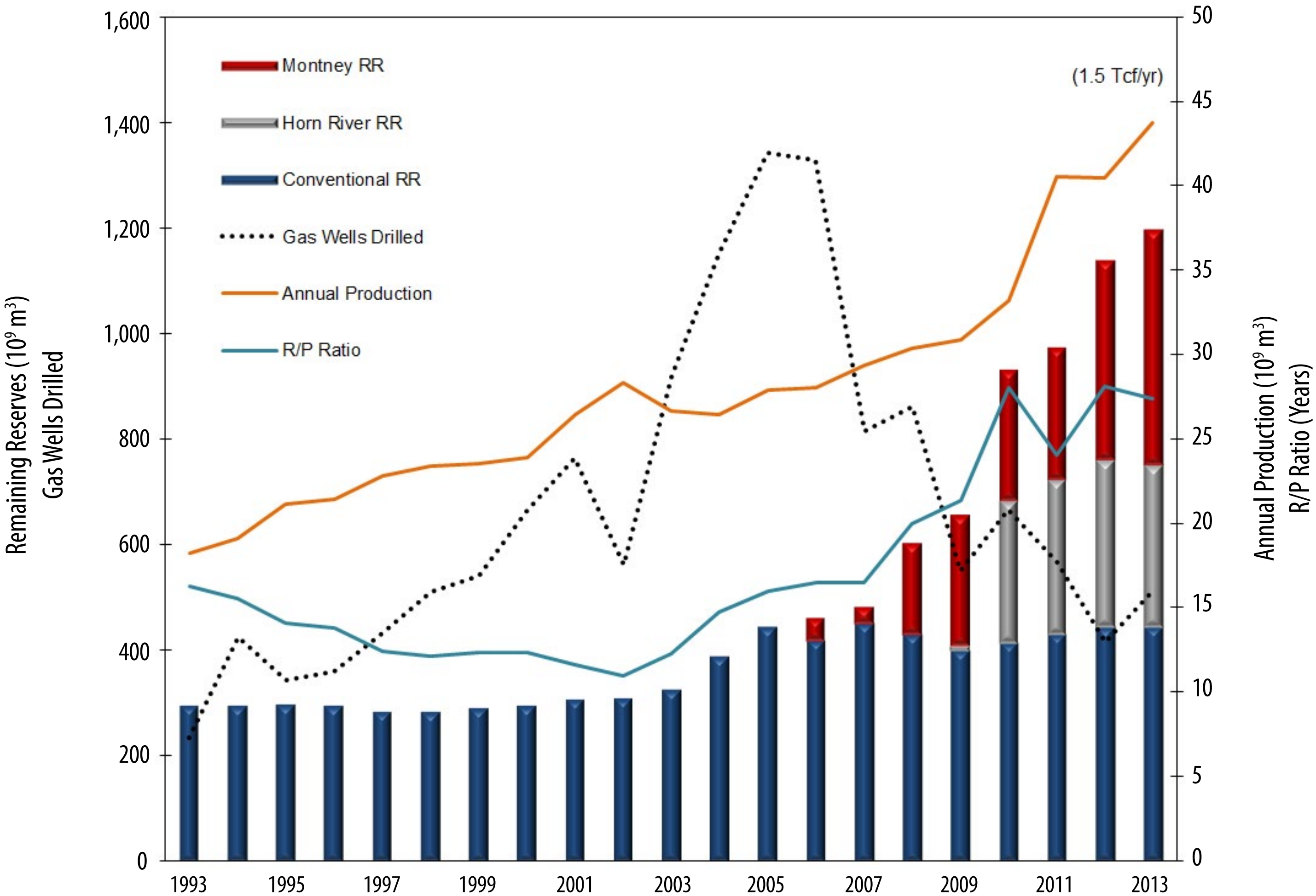


Figure 5 on page 8 presents the Commission’s reserves bookings from 1993 – 2013, showing unconventional Montney and Horn River reserves versus all other reserves grouped as conventional. Looking back to 1993, remaining reserves (RR) were fairly consistent until 2003 when the number of gas wells drilled increased dramatically. Between the years 2003-2006, activity reached record levels (1,300 gas wells drilled in 2006), with predominant targets being: shallow Cretaceous (Notikewin, Bluesky Gething) and Triassic (Baldonnel and Halfway), Deep Basin Cadomin and Nikanassin and Jean Marie platform and bank-edge. However, in 2007, the onset of horizontal drilling with hydraulic stimulation, applied to unexploited shale gas and low permeability gas reservoirs, created a new supply of gas, not just in B.C. but across North America.

Figure 5: Historical Gas Development in B.C.



Annual production in B.C. has risen 42 per cent in the last five years, with the majority (60 per cent) now coming from unconventional reservoirs.

The R/P (reserves to production) ratio has increased significantly in the last five years, from 20 years of supply in 2008 to 27 years in 2013, as unconventional reserve bookings have begun to replace and surpass conventional reserves. Despite limited permeability, unconventional wells with long reach horizontal wellbores and large stimulated reservoir volumes tend to access more reserves on average than typical conventional wells. Reserves, per well drilled, have increased. This trend of increasing unconventional reserves in B.C. is expected to continue, given the large, extensive resource estimates of unconventional gas.

Significant gas reserve increases occurred in 2008 with the booking of Montney reserves, and in 2010 with the introduction of Horn River reserves. In 2013 the remaining reserves continued to rise (up five per cent) due principally to a review of the Northern Montney area, with new drilling and the booking of proven undeveloped reserves (PUDs) following SPEE statistical methods. The Regional Heritage area was not reviewed in 2013 and reconciliation to 2012 only accounted for production losses.

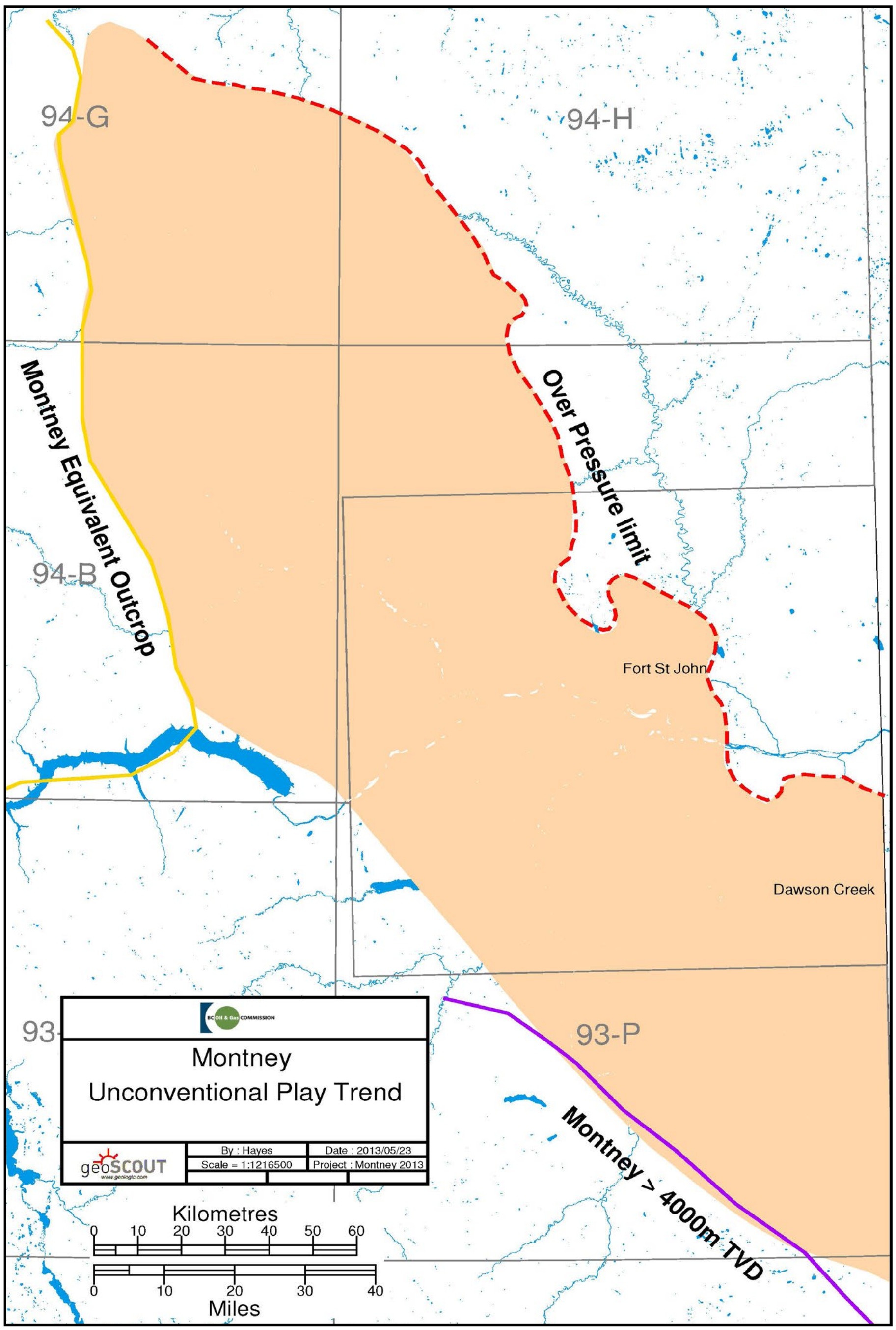
For unconventional reservoirs, the effectiveness of the completion is as important a factor as the quality of the reservoir. A summary of the completion parameters such as number of fracture stages and fluid pumped are included in this report, (in the Unconventional Play sections on the following pages), as indicative of the stimulated rock volume and ultimate recoverable reserves.

Geology, drilling and completions, production and reserve methodology are discussed in the Montney, Horn River Basin, Liard Basin and Cordova Embayment unconventional play sections on the following pages.

Montney - Unconventional Tight Gas Play

The unconventional Montney Play Trend represents 37 per cent (15.7 Tcf) of the province's remaining recoverable raw gas reserves. In 2013, 0.7 Tcf was produced from the Montney, accounting for 46 per cent of total gas production in the province.

Figure 6a. Unconventional Montney Play Trend



Geology

The unconventional Lower Triassic Montney play targets dry gas, liquids rich gas, and oil in over-pressured siltstones along an extensive 29,850 kilometres $(km)^2$ play trend that stretches northwest 200 km from the B.C.-Alberta border near Dawson Creek to the B.C. foothills (Figure 6a).

The unconventional Montney play trend is confined to the northwest by outcrop and to the southwest by depth as it deepens to beyond 4,000 m Total Vertical Depth (TVD). The eastern play limit is defined by the transition to a normal formation pressure regime. While hydrocarbon charge is pervasive throughout the play trend, local reservoir conditions can vary extensively. As such, preferred landing targets within the 300+m thick Montney formation as well as completion methodologies are also locally applied.

Development of the unconventional Montney began in 2007 and by 2012 the Montney had become the single largest contributor to provincial natural gas production volumes. By the end of 2013, Montney production was up 30 per cent over 2012 rising to 63.3 e^6m^3/d (2.24 Bcf/d) at year end. The number of producing wells in 2013 rose to 1,555 up from 1,270 in 2012. Cumulative production climbed to 65.6 e^9m^3 (2.3 Tcf).

In 2013, drilling continued to focus on the rich gas portion of the play trend. As a result, production of NGLs and condensate have risen along with the increase in natural gas volumes. Figure 6b displays the identified dry gas, rich gas and oil trends within the greater Montney Play trend. The relative rise of associated NGLs and condensate production is detailed in Figure 7.

Table 2: Regional Heritage Field Reservoir Parameters

Reservoir Data	Heritage
Depth Range	1,400 – 3,200 m
Gross Thickness	30 – 300 m
TOC Range	~2%
Porosity	2 – 9%
Water Saturation	25%
Pressure	14 – 86 MPa
Pressure Regime	Over Pressure
Temperature	50 – 110° C
H_2S	0 - 1.0%
CO_2	Less than 1% (max 5%)

Figure 6b: Montney Regional Fields and Dry/Wet/Oil Distribution

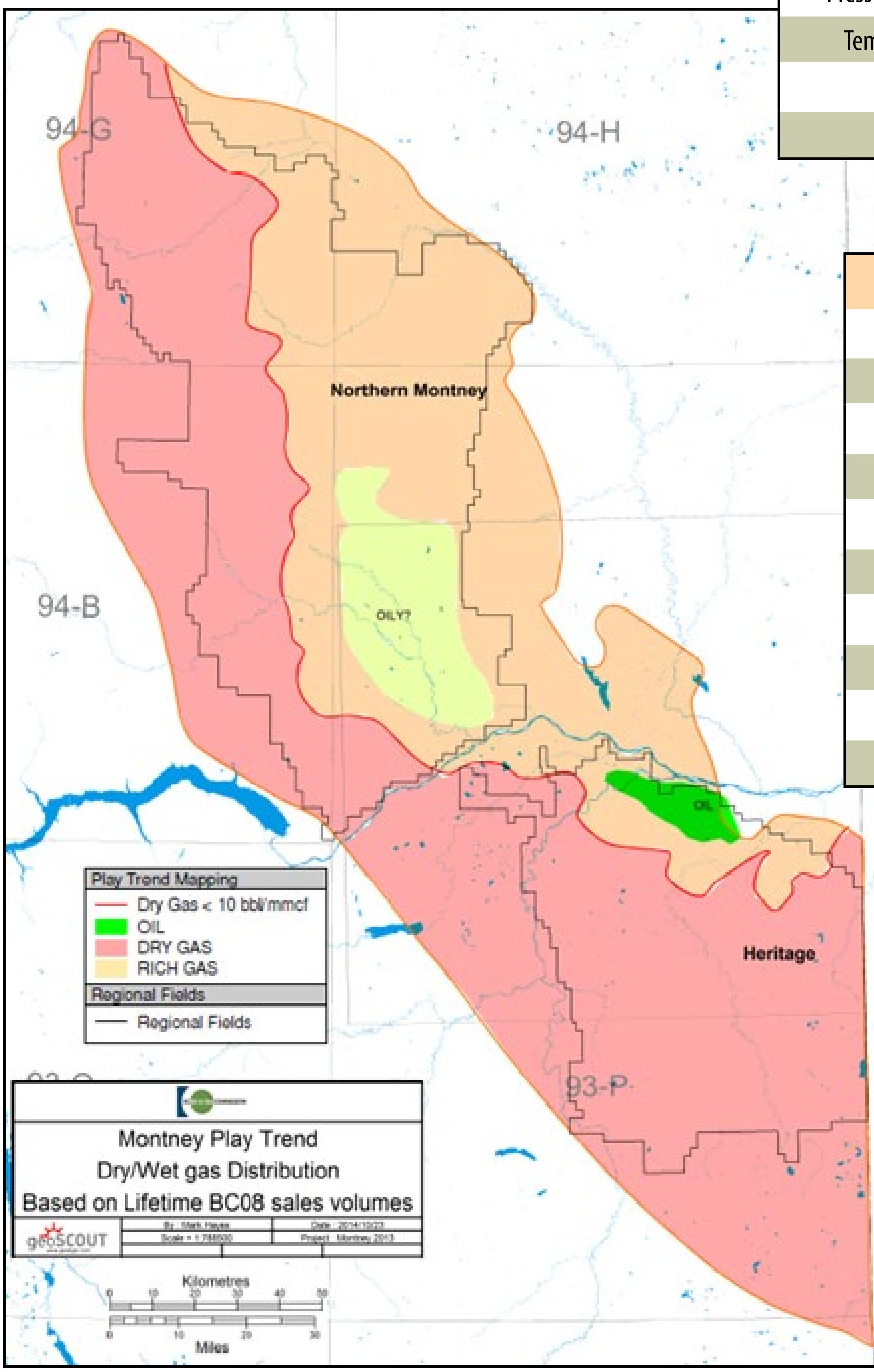
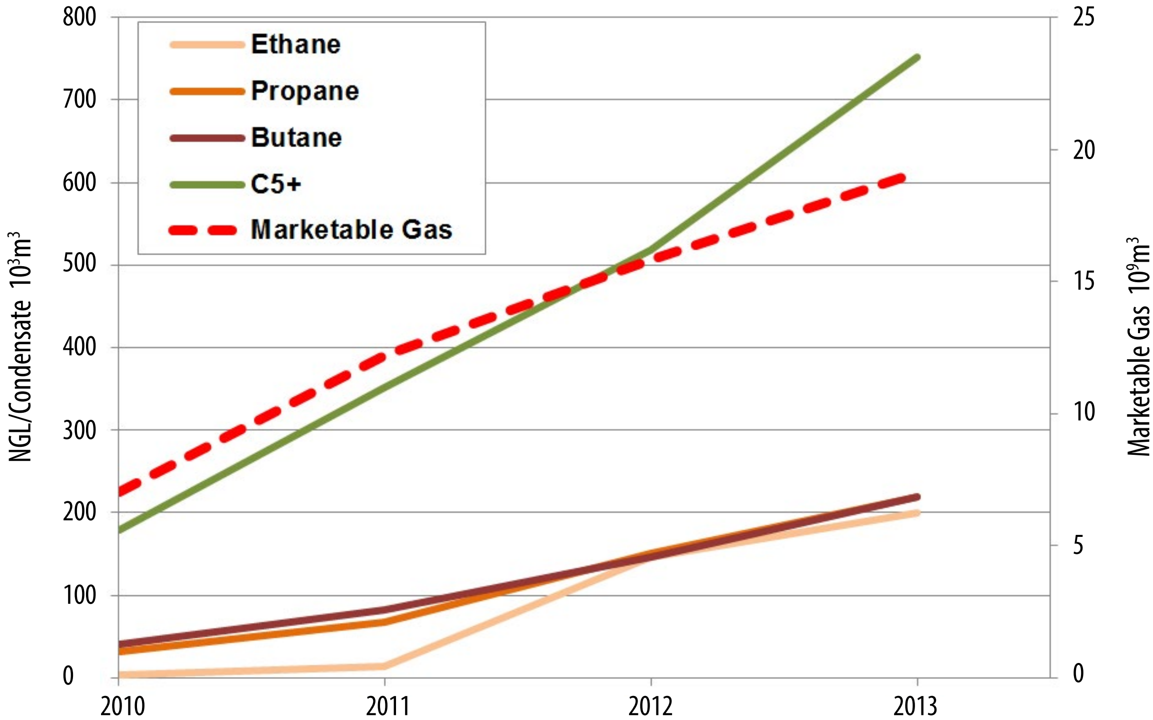


Table 3: Northern Montney Reservoir Parameters

Reservoir Data	Northern Montney
Depth Range	2,000 – 2,400 m
Gross Thickness	30 – 300 m
TOC Range	~2%
Porosity	2 – 9%
Water Saturation	25%
Pressure	14 – 53 MPa
Pressure Regime	Over Pressure
Temperature	51 – 83° C
H_2S	0 - 1.5%
CO_2	Less than 1% (max 5%)

The Regional Heritage Field is comprised of a single pool (Montney “A”) with dry gas and rich gas areas and a small oil leg. The Heritage Field covers a large area and there is a significant range in reservoir parameters. As a general rule porosity and permeability are better to the northeast while formation pressure increases with depth of burial to the southwest especially where the play quickly transitions into the B.C. portion of the Deep Basin Cadomin. There is a significant gas liquids component to the Montney gas in the northeast part of the field in the geographic areas of Septimus, Sunrise and Parkland and a defined oil leg in the region

Figure 7: Annual Montney NGL and Condensate Sales Volumes



of Tower Lake. By end of 2013, 18 oil wells were producing approximately 170 m^3/d (1,100 bbl/d). Cumulative oil production was 80 e^3m^3 (504.0 Mbbl).

Northern Montney (expanded west and south; now three pools)

The Regional Northern Montney Field contains three gas pools; Montney-Doig Phosphate A, Montney A and Montney B. The large areal size of the field translates into significant ranges for the reservoir parameters. Reservoir conditions are further complicated to the west where a portion of the Northern Montney resides within the disturbed belt of the Northern Rockies. As such, the western part of the field can be subject to substantial formation over-pressure, structural thickening and naturally occurring fractures and faults. There is also significant NGLs and condensate production, especially in the geographic areas of north Altares, Inga and Blueberry.

Table 4: 2013 Montney Completion Statistics (Regional Heritage, Northern Montney)

Drilling Data	Regional Heritage	Northern Montney
Average Proppant Placed per Stage (t)	100	150
Total Fluid Pumped (m^3)	7,240	11,740
Average Fluid Pumped per Stage (m^3)	550	1,190
Number of stages	16	10
Completed Length (m)	1,760	1,545
Average Frac Spacing (m)	130	170
6 Month Gas Rate per Stage (Mcf/d)	240	220

Detailed geological mapping of the unconventional Montney play trend is available from the Commission website by downloading the Montney Formation Play Atlas NEBC from the 'Reports' section at http://bcogc.ca/publications/reports.

Drilling and Completions

Completion technology in the Montney is constantly progressing with drilling spacing and completion optimization techniques. Table 4 summarizes the completion statistics for both the Regional Heritage and Northern Montney fields. A typical horizontal well completed in 2013 had an average completed length of 1,760 m (Regional Heritage field) and 1,545 m (Northern Montney field). In June 2013, the Commission introduced online submission of detailed completions data to improve access and tracking of key parameters. Additionally, disclosure of the chemicals included in each fracture treatment is available in the public database www.fracfocus.ca.

Production

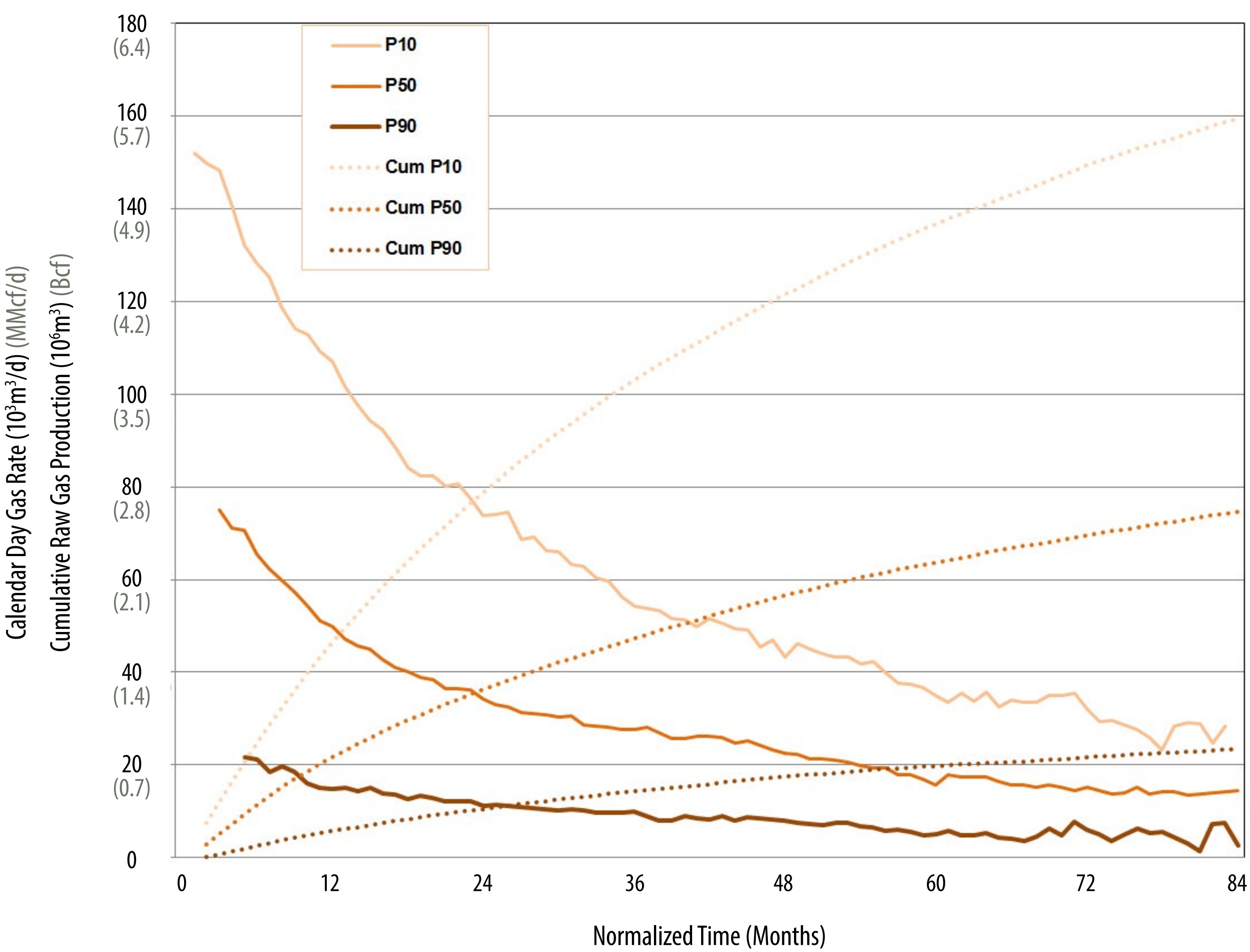
Figure 8 presents type curves of Montney production across the Heritage and Northern Montney regional fields. Calendar day raw gas rate and cumulative gas production (dashed lines) are plotted versus normalized time (months). The type curves were generated to show the P10, P50 and P90 well performance. The P50 well initial rate is approximately 75 $10^3m^3/d$ (2.7 MMcf/d), declining sharply to under 50 $10^3m^3/d$ (1.7 MMcf/d) in the first year. After seven years, the P50 well has produced a total of 75 10^3m^3 (2.6 Bcf). Interestingly, the P10 results show substantial cumulative production of over 160 10^3m^3 (5.7 Bcf) after seven years of production.

Reserve Methodology

Following the guidance in SPEE Monograph 3, proved undeveloped (PUD) reserves were assigned to the Regional Heritage and Northern Montney pools based on development maturity (calculated using P10/P90 ratios and well count). The Northern Montney falls into the Monograph's early to intermediate development stage while the Heritage Montney falls into the Monograph's mature phase of resource play development.

For the early to intermediate phase of development in the Northern Montney, three PUDs were assigned for every existing well. Monte Carlo simulations were performed to obtain aggregated P90 Estimated Ultimate Recovery (EUR). These values were used to assign reserves to PUDs.

Figure 8: Montney Horizontal Well Type Curves



In the Heritage Montney, where the field is in the mature phase of development, the number of PUDs is calculated using statistical methods. Reserves were assigned to each PUD using aggregated P90 EUR from Monte Carlo simulation.

Existing wells were assigned the P50 EUR in both the Regional Heritage and Northern Montney.

An average resource OGIP of ~250 Bcf/GSU was determined from a collaborative study on The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta, developed by the Commission, the National Energy Board and the B.C. Ministry of Natural Gas Development. As of 2013, the total booked EUR for the Montney is 15.7 Tcf, which represents a 12 per cent recovery factor (RF) of the "proved" gas in place (drilled spacing areas and immediate surrounding) and less than one per cent recovery of the total prospective resource estimate, including unproven sections of the play trend.

A complete record of the reserve estimates for each Montney pool can be found in Table 5 below and is discussed in detail in Appendix II.

Figure 9: Montney EUR Statistics (Bcf/Well)

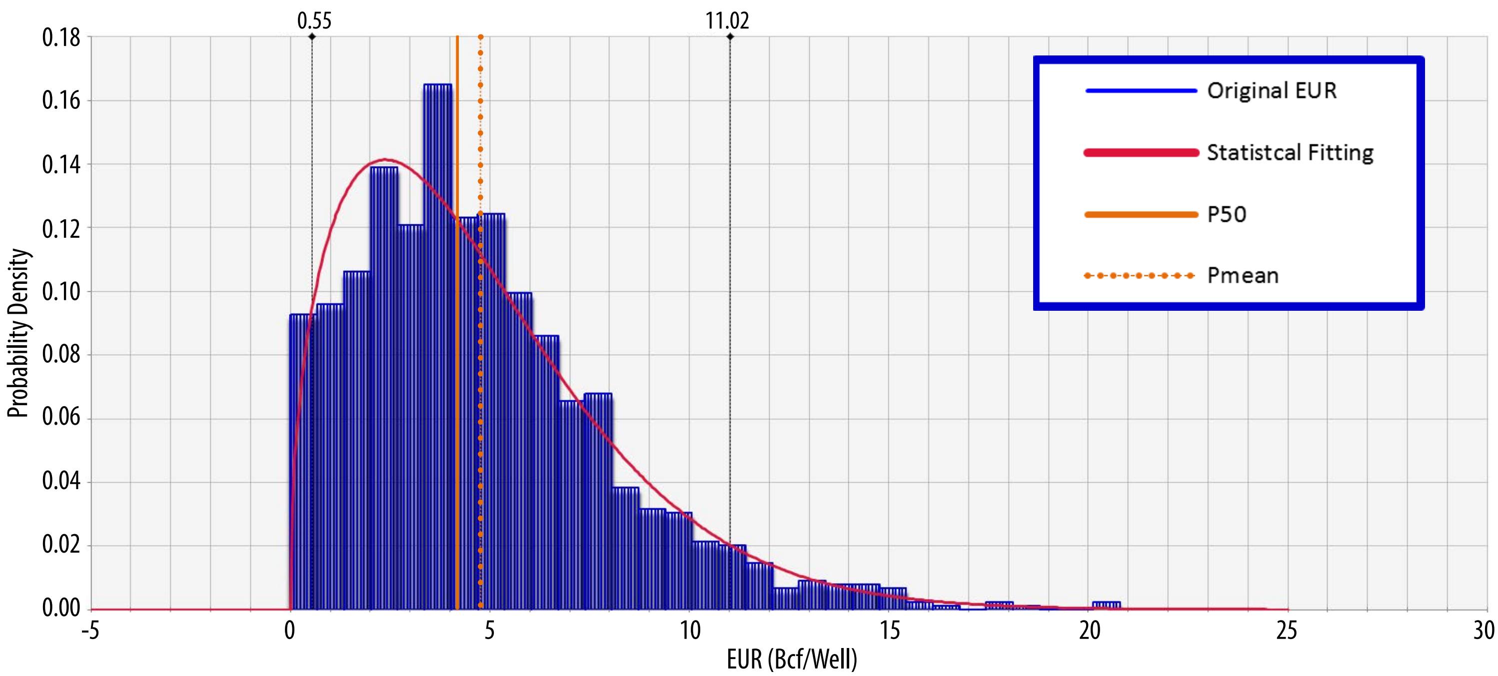


Table 5: Montney Reserves

Field	Pool	Horizontal Well EUR(MMCF) Per Well				Initial Reserves (Raw) Bcf	Remaining Reserves (Raw) Bcf	Existing HZ Wells	HZ PUDs	Existing Vertical Wells	Vertical PUDs
		Pmean	P90	P50	P10						
Heritage	Montney A	5,088	1,099	4,554	9,589	11,776	9,836	952	1,310	211	422
Northern Montney	Montney A	3,508	764	3,103	6,915	2,609	2,455	200	600	18	54
Northern Montney	Doig Phosphate-Montney A	4,443	1,332	3,694	8,432	3,345	3,137	198	594	13	52
Northern Montney	Montney B	2,604	566	2,646	4,439	172	158	23	46	3	n/a
Nig Creek	Montney A					82	71	11	22	0	n/a

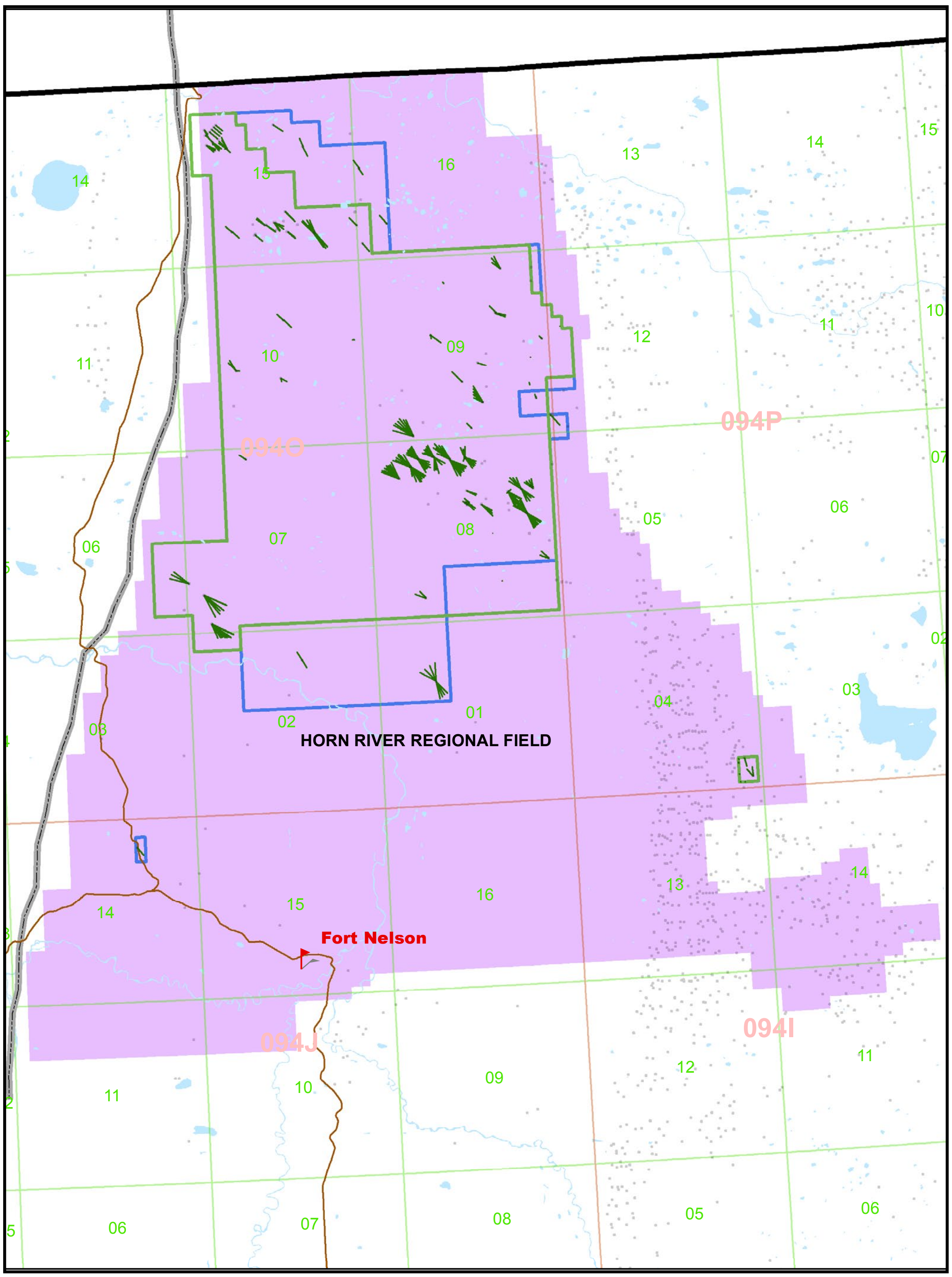
Horn River Basin - Unconventional Shale Gas Play

The Horn River Basin (HRB) represents 25.7 per cent (11.1 Tcf) of the province's remaining recoverable raw gas reserves. In 2013, 0.2 Tcf was produced from the Muskwa-Otter Park and Evie formations within the HRB, accounting for 12.7 per cent of total annual production in the province.

Geology

The HRB is an unconventional shale play targeting dry gas from mid-Devonian aged overpressured shales of the Muskwa-Otter Park and Evie formations. Situated in the northeast of the province (see Fig 1 on page 6), the HRB is confined to the west by the Bovie Lake Fault Zone and to the east and south

Figure 10: Pool Designation Areas (PDA) within the Horn River Basin



by the time equivalent Devonian Carbonate Barrier Complex. Stratigraphically, the organic rich siliciclastic Muskwa-Otter Park and Evie shales of the Horn River group are overlain by the Fort Simpson shales and underlain by the Keg River platform carbonates.

Muskwa and Otter Park formations were mapped in combination and analyzed as one interval, with the Evie formation evaluated and mapped separately. A regional mapping project has been completed, and the Horn River Basin Unconventional Shale Gas Play Atlas was published in June 2014. Mapping completed thus far has defined areas of reservoir variability within the HRB, particularly within the Otter Park formation. Figure 10 denotes wells drilled and the pool designation areas (PDAs) for the Muskwa-Otter Park and Evie shale formations. A general range of reservoir parameters is provided in Table 6.

Table 6: Horn River Shale Reservoir Parameters

Reservoir Data	
Depth Range	1,900 – 3,100 m
Gross Thickness	140 – 280 m
TOC Range	1 – 5%
Porosity	3 – 6%
Water Saturation	25%
Pressure	20 – 53 MPa
Pressure Regime	Over Pressure
Temperature	80 – 160° C

Due to the depths and corresponding high temperatures and pressures of the Muskwa-Otter Park and Evie shale formations in the HRB, the recoverable gas is sweet dry gas, >83 per cent methane, with trace amounts of ethane (0.2 per cent), and heavier hydrocarbon components, C_3+ (<0.1 per cent). The majority of gas analyses show no H_2S, or very low levels, with slightly higher values in the Evie (Table 7). CO_2 content in the recoverable gas averages 10 per cent in the Muskwa-Otter Park formations and 13 per cent in the Evie formation, and generally increasing with depth in the HRB.

Development History

The HRB has been of interest since 2005, when horizontal drilling and multi-stage hydraulic fracturing technology from the analogous Barnett shales in Texas was applied to investigate economic recovery. Prior to this, there were very few penetrations in the Basin as operators were targeting Devonian pinnacle reefs, with shale then considered a seal and source rock for gas.

Drilling in the HRB represented only eight per cent of the total drilling activity in 2013; predominated by activity in the Montney area. A total of 376 wells have been drilled across the HRB targeting shale gas; 298 horizontal and 78 vertical. The play concept has extended several kilometres south and east of the pre-existing production as a result of 2013 drilling activity.

Drilling and Completions

Advancements in horizontal well technology and hydraulic fracturing were key to unlocking reserves in the HRB. Up to 20 horizontal wells per drilling pad were stimulated, with approximately 23 stages per well. The majority of wells were stimulated with slickwater fracture treatments having approximately 79,500 m^3 of water placed along with 2,000 - 5,200 tonnes of sand per well. These values are based on 12 wells completed in 2013.

Microseismic monitoring is used extensively in the HRB to identify faults, optimize completion design and study fracture growth. To date, the overlying Fort Simpson shale has been demonstrated to be a highly effective fracture barrier.

Water Usage and Disposal

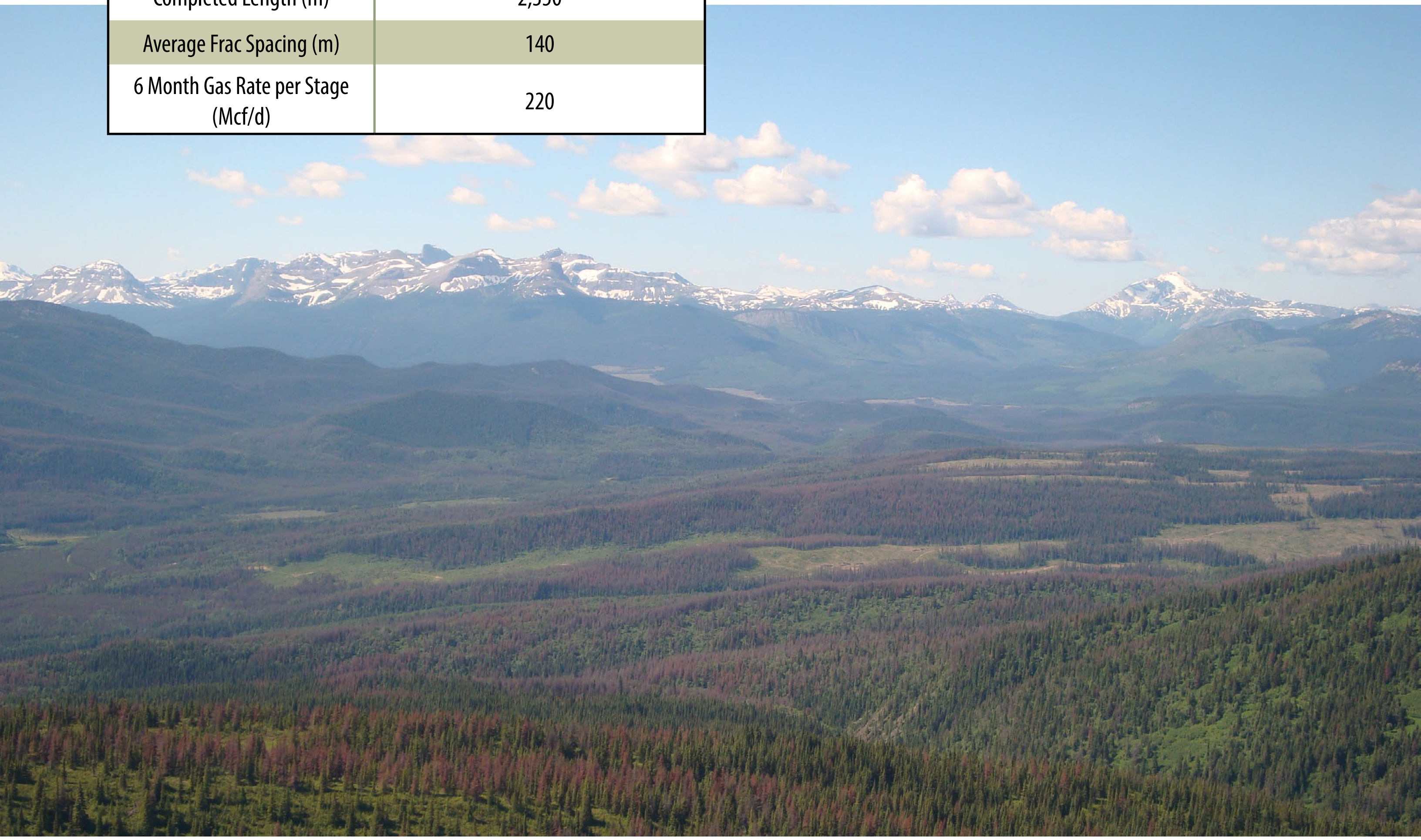
The eastern flank of the HRB contains favorable Mississippian strata (Debolt formation) for sourcing and disposing of water necessary for large scale hydraulic fracture operations. Mississippian sourced water in the Horn River area is non-potable (15,000 – 40,000 mg/l total dissolved solids), which significantly reduces the demand for water from other sources. This extensive deep subsurface Debolt regional aquifer essentially allows source/disposal recycling of load water.

Table 7: Horn River Gas Composition, Mole Percentage

Gas Composition, Avg (Min-Max) %	Muskwa-Otter Park	Evie
Methane (C_1)	89 (83 – 98)	85 (80 – 98)
Ethane (C_2)	0.16 (0 – 1)	0.1 (0.01 – 0.7)
NGLs (C_{3+})	0.05 (0 – 4)	0.09 (0 – 4)
CO_2	10 (0 – 14)	13 (0 – 18)
H_2S	0 (0 – 0.1)	0.02 (0 – 0.1)

Table 8: Horn River Shale Drilling and Completions (2013)

Drilling Data	
Average Proppant Placed per Stage (t)	150
Total Fluid Pumped (m^3)	79,500
Average Fluid Pumped per Stage (m^3)	3,456
Average Number of Stages	23
Completed Length (m)	2,350
Average Frac Spacing (m)	140
6 Month Gas Rate per Stage (Mcf/d)	220



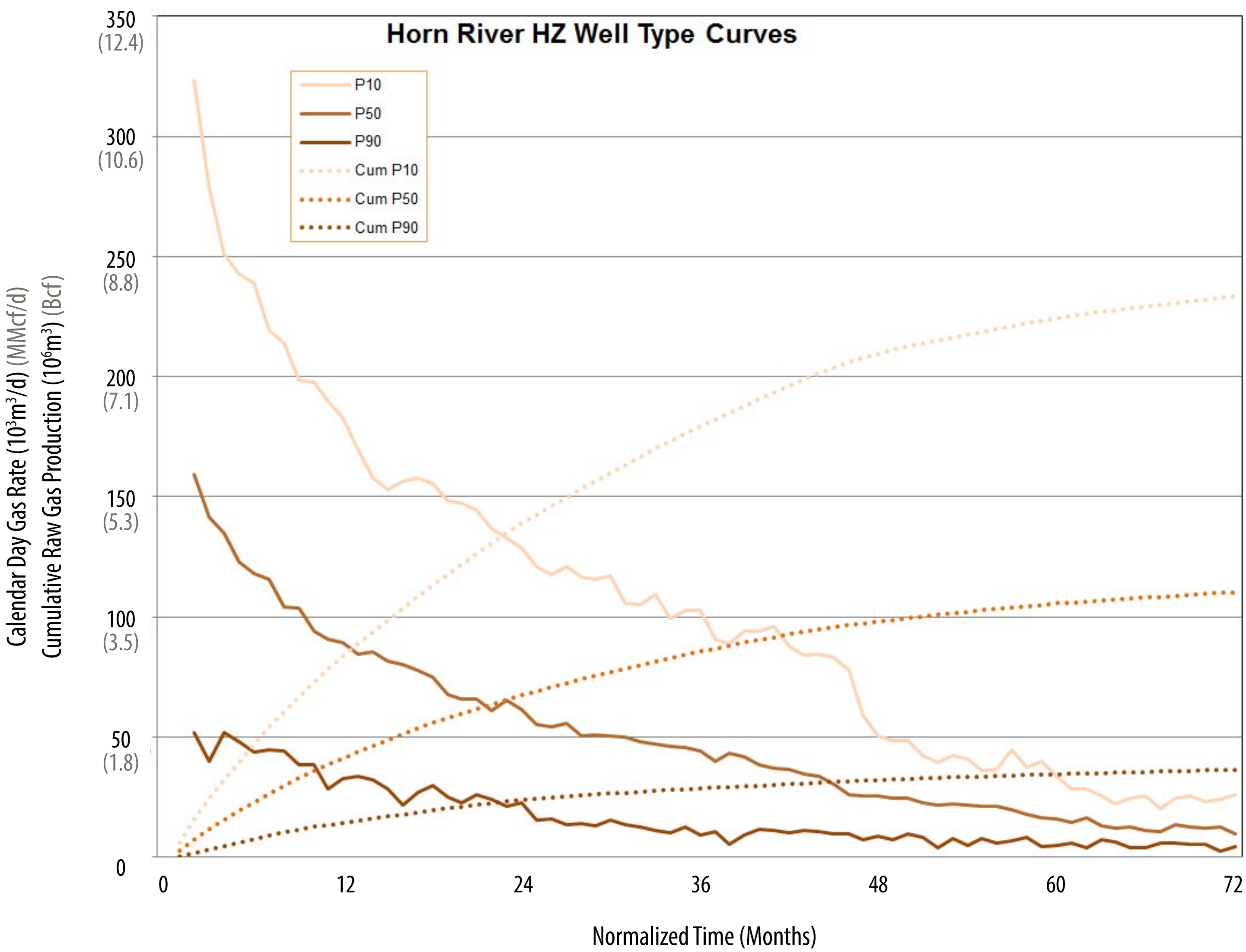
Production

From 2012 to 2013, a typical horizontal well in the HRB exhibited an initial peak gas rate of 160 $10^3m^3/d$ (5.6 MMcf/d), declining 44 per cent in the first producing year, and gradually reaching boundary dominated flow (after 4+ years) due to the ultra low permeability of the reservoir and complex fractures created from hydraulic stimulation. Figure 11 presents HRB type curves of P10, P50 and P90 horizontal well performance. After 40 months, the P50 well produced 90 10^6m^3 (3.2 Bcf).

Reserves Methodology

Initial gas reserves for the HRB were calculated volumetrically since the initial evaluation was conducted by the Commission in 2010. The pool designation areas have expanded since this time and currently represent ~30 per cent of the total prospective area. Proved plus probable reserves (incorporating undeveloped PUDs) are calculated using a 25 per cent RF for shale gas. Future revisions, incorporating decline analysis and statistical techniques used for Montney reserves, will occur in the future.

Figure 11: Horn River Horizontal Well Type Curves



Liard Basin - Unconventional Shale Gas Play

Exploration in the Liard Basin started in 2008 and had a preliminary EUR of 2,933 $10^6 m^3$ (0.1 Tcf) booked in 2013, based on production from four existing wells (two vertical wells and two horizontal wells).

A major structural feature, the Bovie fault zone, separates the Liard from the HRB. The Liard Basin has more than five km thickness of sedimentary rocks preserved including thick, organic shales within the upper and lower Devonian Besa River strata.

Initial reservoir pressure within the upper Besa River shales is 85.2 MPa. Such over-pressure is indicative of a sealed hydrocarbon system, with encouraging implications for well productivity and resource density. Reservoir pressures in the adjacent HRB range from 21 to 53 MPa; significantly lower than those seen in the Liard to date.

Figure 12: Northeast B.C. Shale Basins - Liard, Horn River and Cordova Embayment

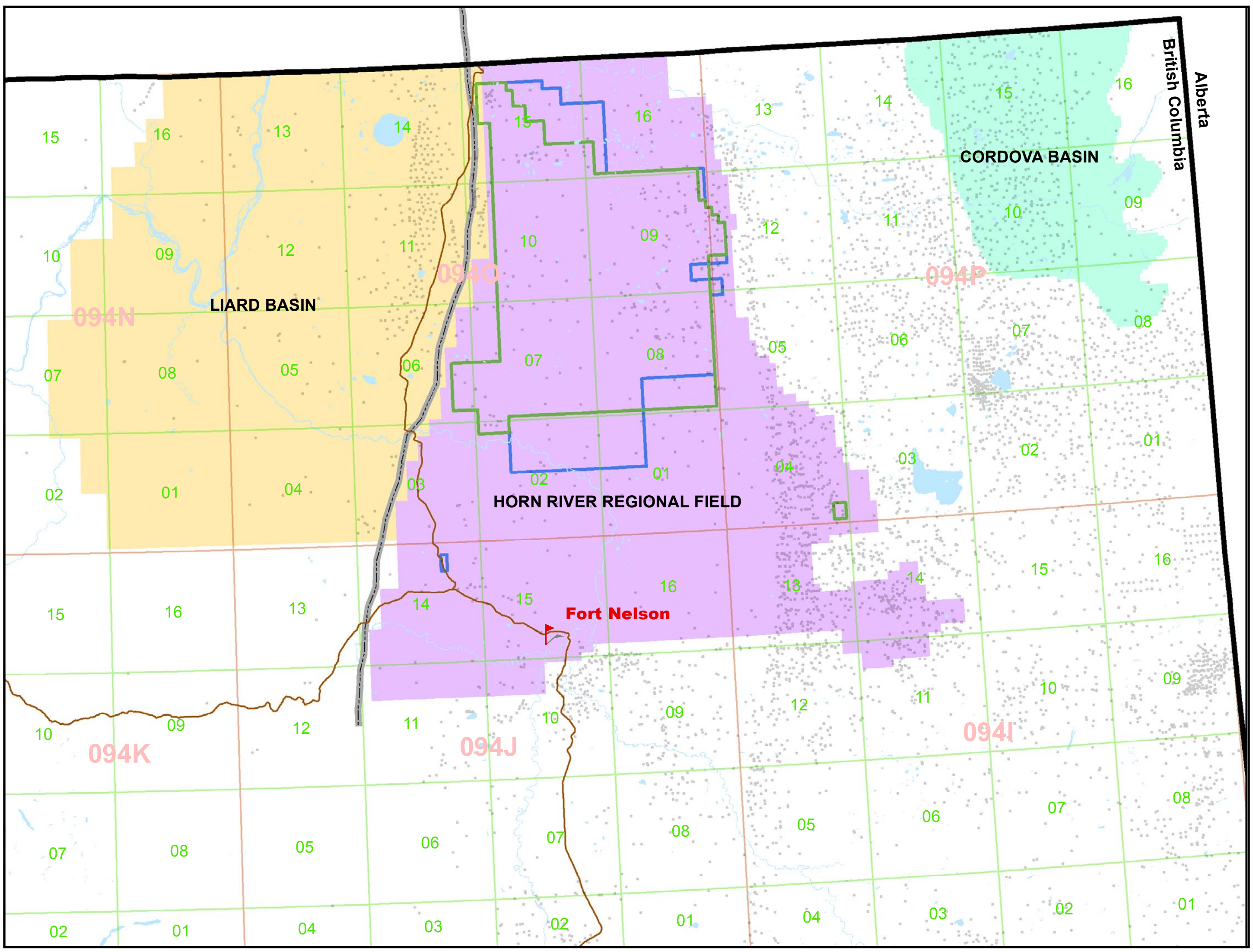
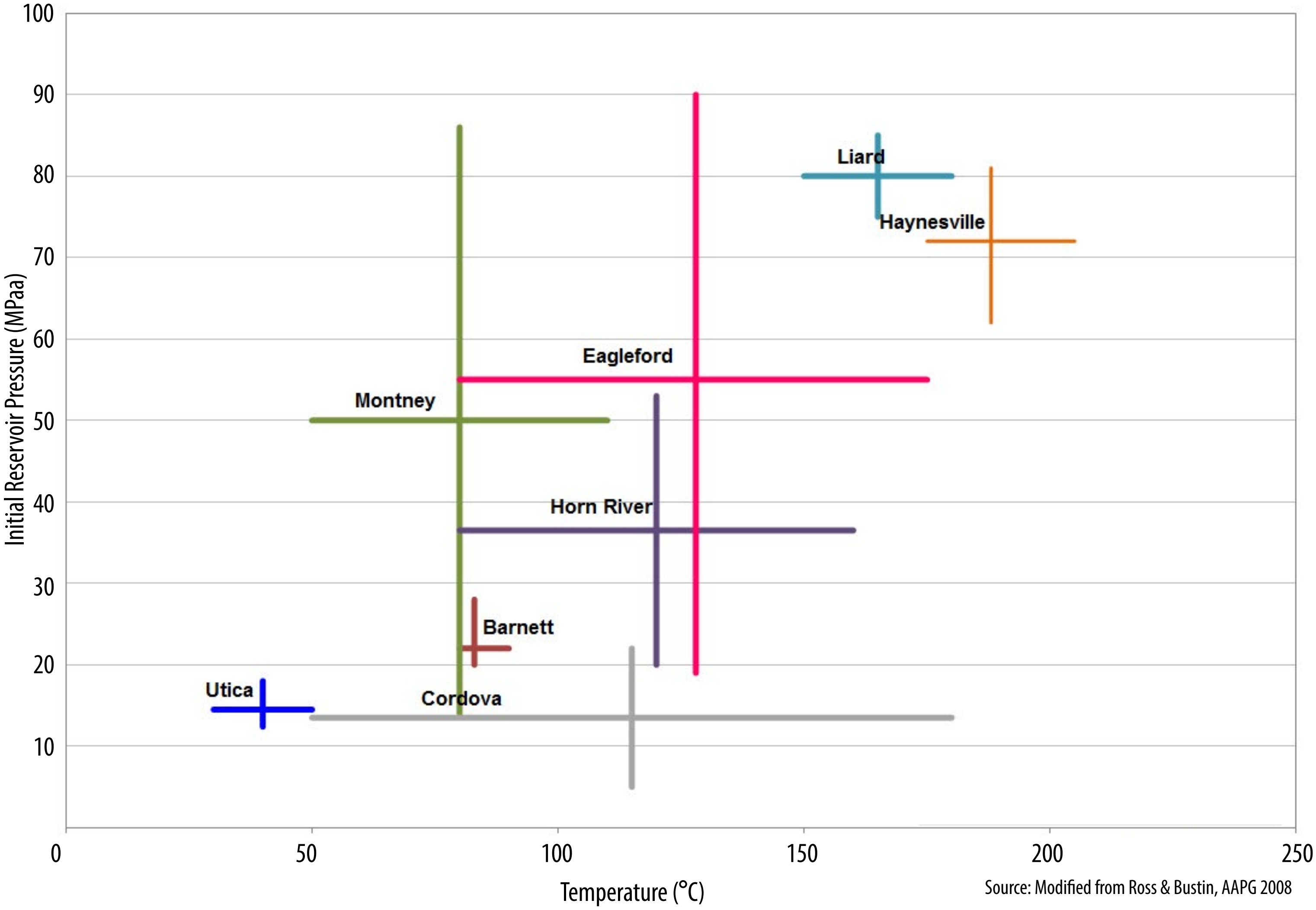


Figure 13: Pressure versus Temperature Plot



Source: Modified from Ross & Bustin, AAPG 2008

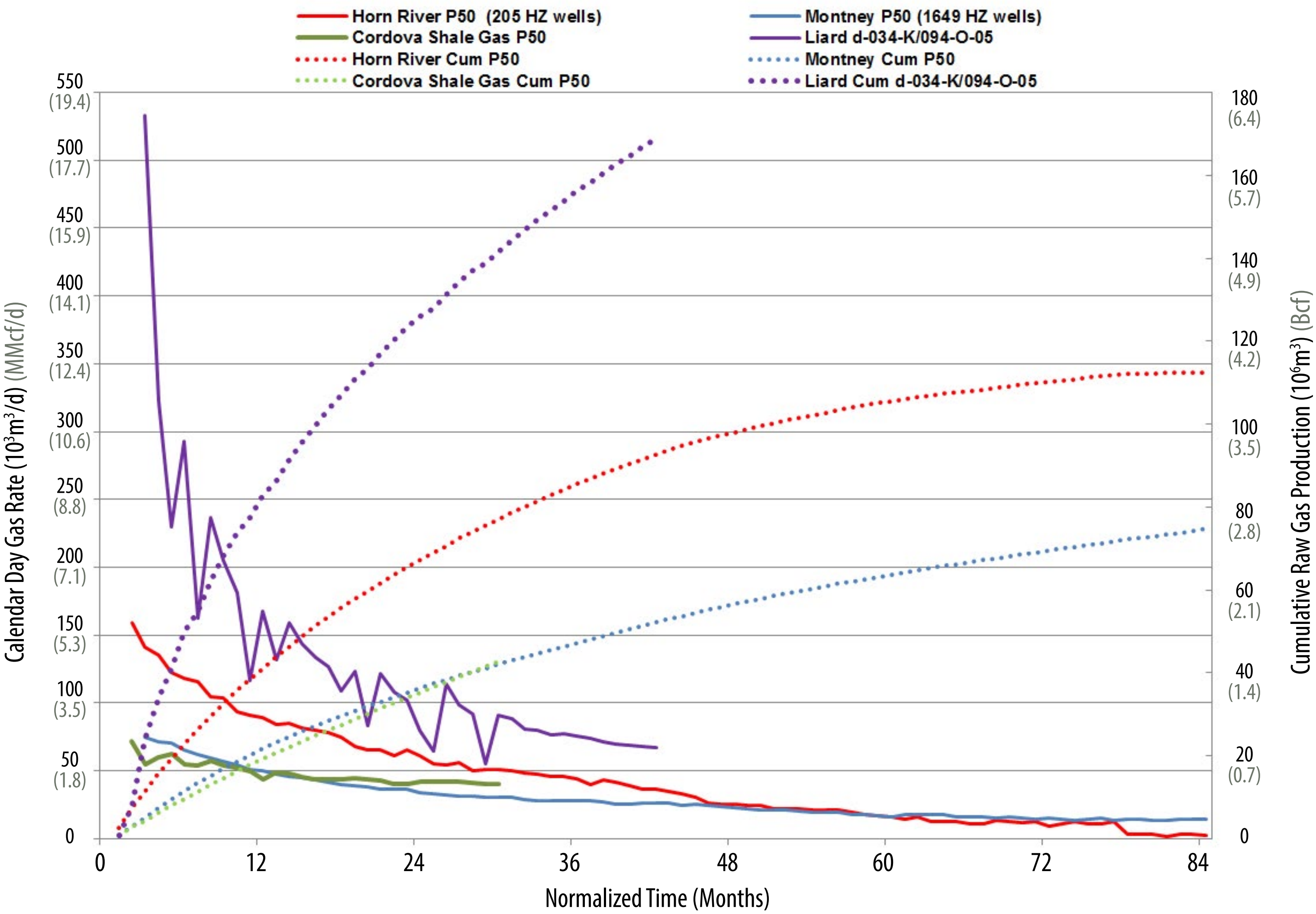
Gas analysis from the three Liard wells drilled to date indicates CO_2 content of ~ seven per cent; lower than the 13 per cent observed in the western portions of the Horn River. Preservation of the relatively high methane content of the gas may be due to a lower than expected temperature gradient. Although much deeper than even the deepest portions of the HRB, the temperatures at the upper Besa River level are similar to the maximum temperatures seen in the Horn River.

The shale gas potential of the Besa River formation was tested with the drilling and stimulation of three vertical wells and two horizontal wells in 2009-2013, in an area previously devoid of deep well tests. Test results (7 MMcf/d vertical well and 30 MMcf/d HZ well) and production was very promising and among the best of any shale gas play in North America.

Using decline analysis, the Commission forecasts an EUR of 8 Bcf/well to the vertical wells and 19 Bcf to the horizontal well. With six stimulations over a 900 m horizontal section, (1,500 t sand; 23,000 m^3 water), the Commission forecasts over 3 Bcf/frac for the horizontal Liard well, compared with 1 Bcf/frac for the Horn River and 0.5 Bcf/frac for the Montney, on average.

The promising results of the first horizontal Liard well are shown in Figure 14 in relation to the P50 horizontal type well in the Montney and Horn River. Peak initial rate from the Liard well is significantly higher than that of either the average Horn River or Montney well.

Figure 14: Comparison of Montney, Horn River, Liard and Helmet HZ Type Curves



Cordova Embayment - Unconventional Shale Gas Play

The Cordova Embayment, similar to the HRB, is an unconventional shale play targeting dry gas from mid-Devonian aged shales of the Muskwa-Otter Park and Evie Formations. Situated eastward of the HRB, the Cordova Embayment is located approximately 130 km northeast of Fort Nelson, covers approximately 2,700 km^2, and is bordered by the time equivalent Devonian Carbonate Barrier Complex (see Figure 12 on page 18). Stratigraphically, the organic rich siliciclastic Muskwa-Otter Park and Evie shales of the Horn River group are overlain by the Fort Simpson shales and underlain by the Keg River platform carbonates.

As with the HRB, the Cordova Embayment mapping combines the Muskwa and Otter Park formations into one interval, with the Evie formation evaluated and mapped separately.

Although not yet explored to the extent of the HRB, and having thinner and more normally pressured reservoir, drilling to date indicates prospectivity within each of the shale intervals over significant portions of the Cordova Embayment. The area contains a significant number of wells and infrastructure for development of the overlying Helmet field Jean Marie formation.

The location of the Cordova Embayment, in relation to the HRB and Liard shale basin, is shown in Figure 10 on page 18. A general range of reservoir parameters is provided in Table 9.

Table 9: Cordova Shale Reservoir Parameters

Reservoir Data	
Depth Range	1,500 – 2,300 m
Gross Thickness	70 – 120 m
TOC Range	2 – 5%
Porosity	3 – 6%
Water Saturation	25%
Pressure	5 – 22 MPa
Pressure Regime	Under pressure to normal
Temperature	50 – 180° C

The average CO_2 content in the Cordova Embayment is eight per cent, slightly lower than the 10- 13 per cent present in the HRB. There are trace amounts of H_2S (<0.6ppm).

Table 10: Cordova Shale Drilling and Completions (2011-2013)

Drilling Data	
Average Proppant Placed per Stage (t)	225
Total Fluid Pumped (m^3)	43,520
Average Fluid Pumped per Stage (m^3)	3,050
Number of Stages	15
Completed Length (m)	1,765
Average Frac Spacing (m)	150
6 Month Gas Rate per Stage (Mcf/d)	120

Development History

The first gas wells in the Cordova Embayment targeting shale were rig released in 2008. As of December 31, 2013, 21 horizontal wells and five vertical wells were drilled. The majority of the drilling occurred in 2011 (14 wells), with five and seven wells drilled in 2012 and 2013, respectively. Annual production for 2013 was 338 $10^6 m^3$ (11.9 Bcf), with 21 producing wells at year end.

Drilling and Completions

The completions approach in the Cordova was comparable to the Horn River. The average values from the horizontal wells completed in 2012-2013 are summarized in Table 9. The average well has a 1,765 m horizontal cased hole lateral and received hydraulic stimulation with 15 slickwater fracture stages using ~43,500 m^3 of water and 3,200 t of sand. Nitrogen (N_2) gas was employed in two wells as an energizer.

Production

The average horizontal type well for Cordova is shown in comparison to the Montney, Horn River and Liard in Figure 14. Although initial rates are lower than the neighboring Muskwa-Otter Park and Evie shales of the HRB to the west, (despite similar completion techniques), the decline appears to be more stable. More drilling and production is required to substantiate the Cordova type well.

Reserves Evaluation Methodology

A reserves revision was performed using production decline analayis in 2013, which updated the remaining reserves (raw) to 2,479 $10^6 m^3$ (87.6 Bcf). Similar to the Horn River, future reserve revisions, incorporating decline analysis and statistical techniques used for the Heritage Montney reserves, will occur upon reaching a larger data set of drilling and production.

Reserves values are noted in report tables (Detailed Gas Reserves By Field and Pool - as listed in the Table of Contents) within the Cordova play area Muskwa-Otter Park "A" and Evie "A" pools, as a separate regional field has not yet been designated (these wells are currently mapped within the Helmet field).

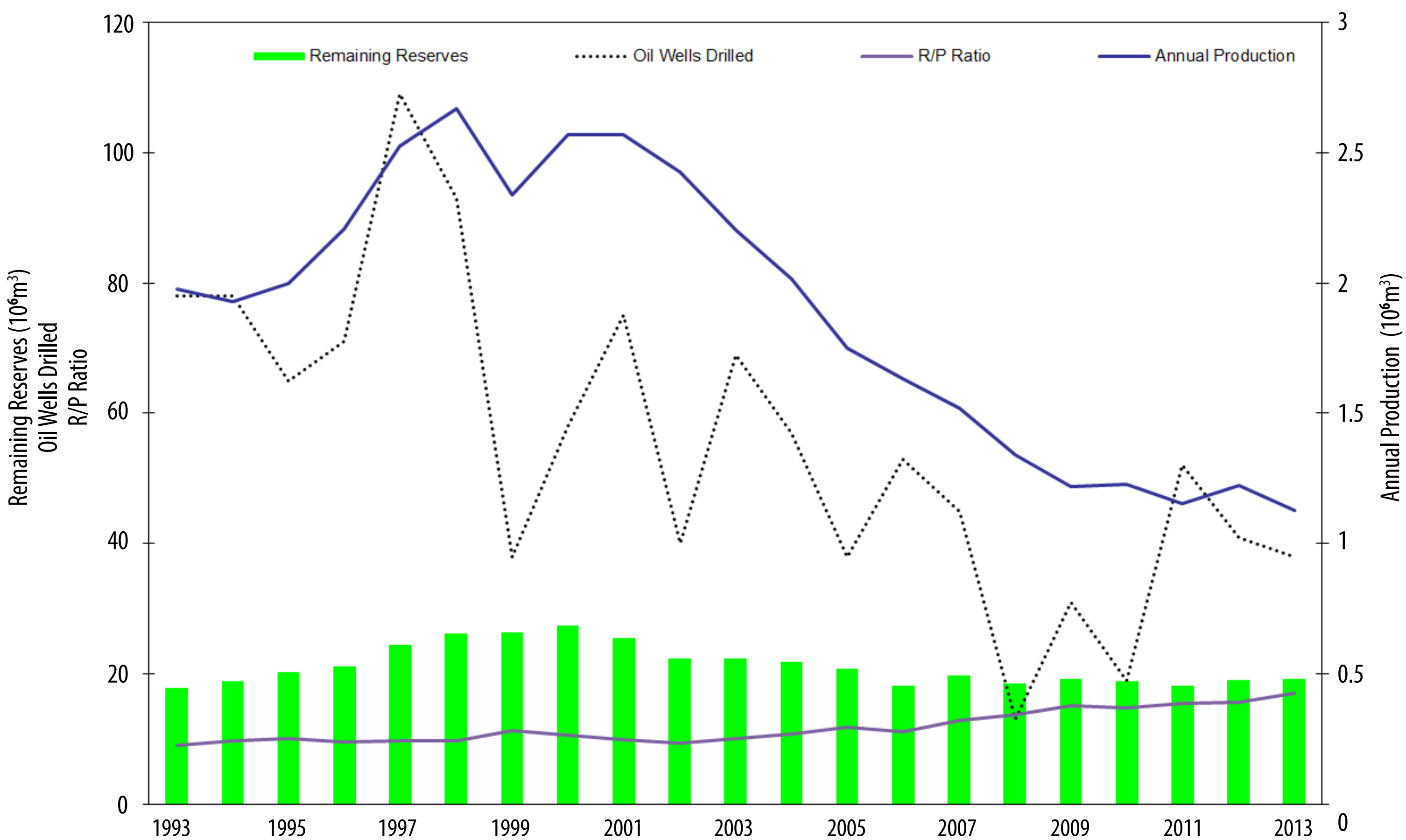
B. Oil Reserves

Oil reserves increased one per cent in 2013, for a total of 19.3 10^6m^3 remaining oil reserves as of December 31, 2013. The majority of this increase came from the revision of the Eagle - Belloy-Kiskatinaw pool, the Blueberry - Debolt "B" pool and the Boundary Lake - Boundary Lake "A" pools. Annual provincial oil production was 1.1 10^6m^3, which was slightly down from 2012. In 2013 there were 38 new oil production wells drilled.

Historical oil reserves, drilling, production and R/P ratio are plotted in Figure 15 below. Oil production reached a peak of 2.5 10^3m^3/year in 1998, then declined until 2010 when it began to stabilize with continued horizontal drilling and waterflood pressure maintenance. The R/P ratio has been steady since 2009, with ~15 years of reserve life booked. Oil well drilling has fluctuated in recent years, from a low in 2008 (13 wells), to a high in 2011 of 52 wells, primarily from horizontal drilling in the Hay River- Bluesky "A" pool and the Heritage Montney "A" pool.

The distribution of remaining oil reserves by field is shown in Figure 16. The Boundary Lake – Boundary Lake "A" pool and the Hay River - Bluesky "A" pool are the largest contributing pools to overall remaining oil reserves in the province, with the newly discovered Heritage Montney "A" pool contributing three per cent to total reserves in its early stage of development.

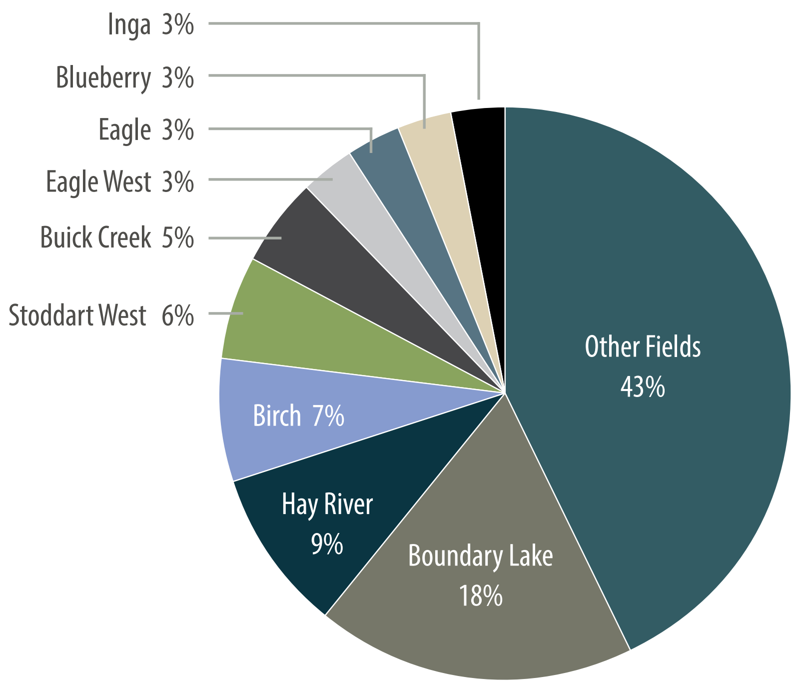
Figure 15: Historical Oil Development in B.C.



Half of the remaining oil reserves in B.C. come from pools with secondary recovery pressure maintenance schemes, predominantly waterfloods. A summary of the EUR and remaining reserves for each of the 49 pools under waterflood is provided in Table A-4: Oil Pools Under Waterflood.

Gas injection recovery schemes account for one per cent of remaining oil reserves and occur in six oil pools (see Table A- 5: Oil Pools Under Gas Injection). Many of these pressure maintenance schemes have been in operation for over 25 years and are potential candidates for tertiary recovery.

Figure 16: Remaining Oil Reserves by Field



Heritage - Montney "A" Oil

A significant addition to oil reserves is the Heritage Montney "A" oil pool in the central Tower Lake area of the Montney Play trend (see Figure 6b). The regionally extensive Triassic Montney formation trends from dry to rich gas, with a less mature hydrocarbon oil pool in an area of lower pressure and shallower depth. Given the potential of the resource and lack of analogous reservoirs, the Commission is focused on determining best production practice for maximizing recovery.

By 2013 there were 30 Montney oil wells on production. A forecasted total EUR assigned to the Heritage Montney "A" oil leg was 526.6 10^3m^3 (3,312 Mbbl), which represents a two per cent RF of the original oil in place (OOIP) of 26,329 10^3m^3 (165,591 Mbbl). Reservoir parameters are provided in Table 11.

Table 11: Heritage Montney "A" Oil Pool Reservoir Parameters

Reservoir Data	Reservoir Parameter
TVD top to Montney	1,800 – 2,100 m
Initial Pressure	19 – 28 MPa
Pressure Regime	Slightly overpressure (10-12 kPa/m)
Temperature	60 – 70° C
API Gravity	45°
Solution GOR	200

C. Condensate and NGL Reserves

Condensate and natural gas liquids (NGLs) production, in association with natural gas, are increasing in B.C. predominately due to the development of gas/liquids rich portions of the Montney Play trend (see Figure 7 on page 11). Across all of B.C., the condensate and NGL production increased by 17.5 per cent and 8.4 per cent respectively, while oil production decreased by 5.9 per cent (Figure 17). Mapping of the lifetime cumulative volumes ratio of C_5^+ and oil is shown in Figure 17. Significant volumes of NGL and condensate are recovered in the northeast section of the Heritage Montney field with ratios reaching as high as 50 – 100 bbl/mmcf. The Commission defines an oil area and a new "oily" pool currently under investigation.

Condensate and NGL reserves are currently calculated using the gas composition and on the yield achieved at the plant to which the associated raw gas reserves are delivered. In 2013 condensate reserves increased to 20.8 e^6m^3 from 2012 (16.2 e^6m^3), which is a 28.3 per cent increase. NGLs increased 21.8 per cent from 2012 to 2013 (44 e^6m^3 to 53.6 e^6m^3) and is indicative of the activity in the liquids rich areas in B.C.

The Commission is continuing with a comprehensive review of condensate and NGL reserves, given the increased significance in recent years.

Figure 17: Annual Oil, Condensate and NGL Production

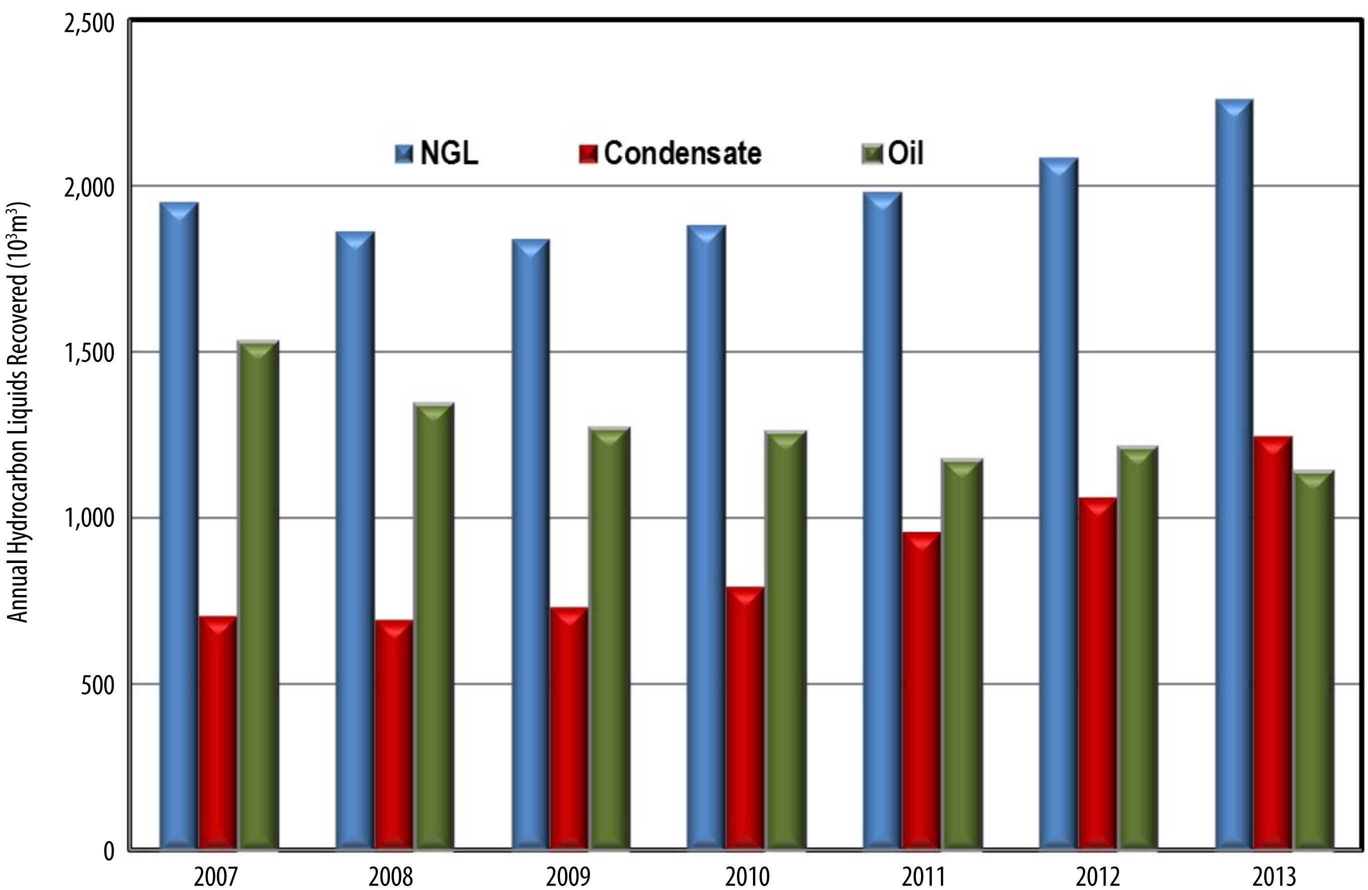
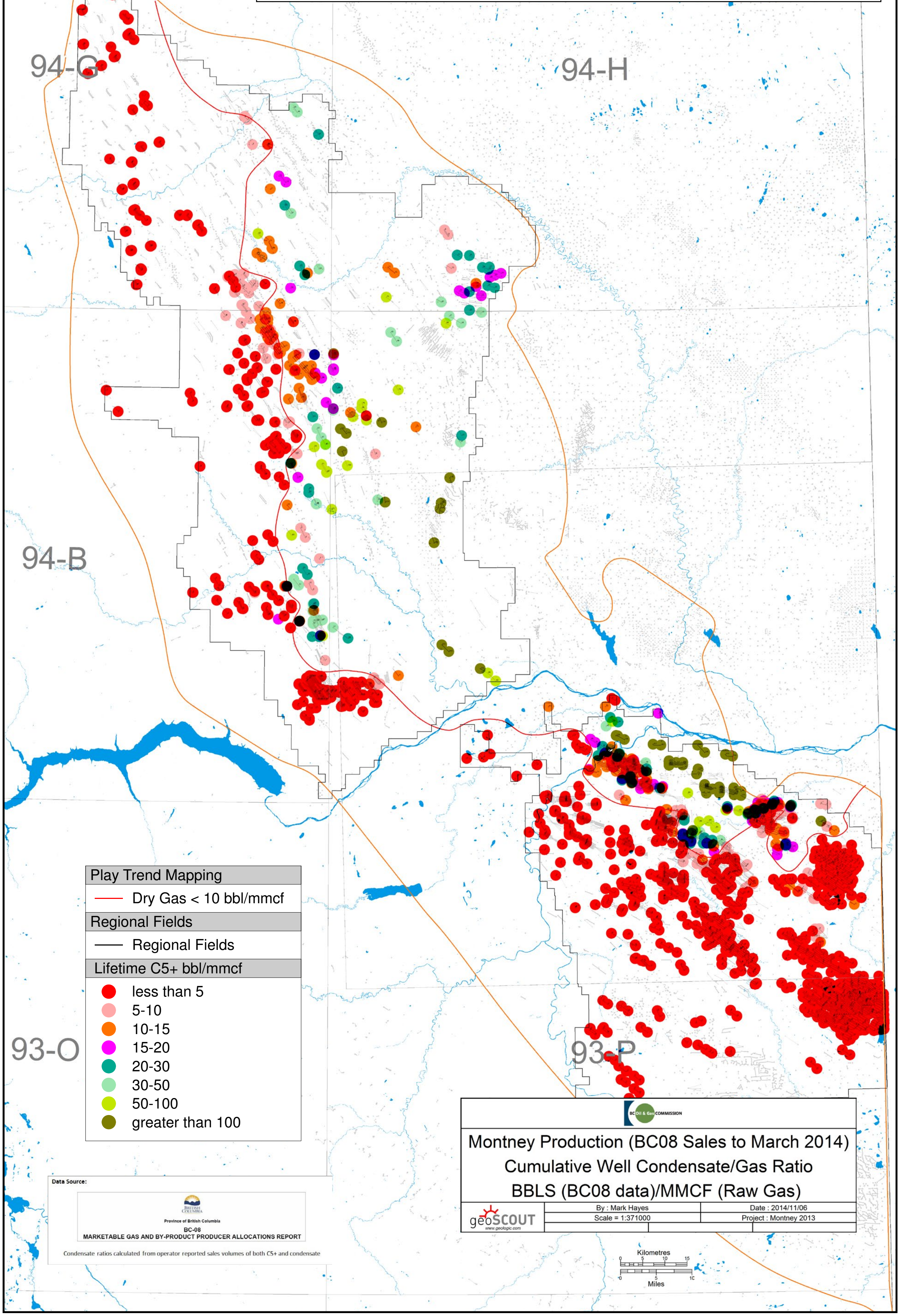


Figure 18: LIfetime Cumulative Volumes Ratio C_5^+ and Oil Sales (Bbl)/Raw Gas (mmcf)



D. Sulphur Reserves

Sulphur may be recovered from natural gas containing H_2S. In B.C., most by-product H_2S is disposed, in combination with $C0_2$ extracted from raw gas, in approved disposal wells. Sulphur recovery is not a significant resource in British Columbia.

Sulphur reserves are calculated based on the yield achieved at the plant to which the associated raw gas reserves are delivered. As of Dec. 31, 2013, there were 17.7 10^6 tonnes of sulphur reserves remaining. This was a 12.7 per cent increase from 2012, as a result of a technical revision of the Boundary Lake – Belloy D, I, J and L pools.

A map of the distribution of H_2S by field can be found on the Commission website at http://bcogc.ca/industry-zone/documentation/Reservoir-Engineering.

Of significance, the most active areas in the Montney and Horn River contain little to no H_2S (Montney, less than 0.3 per cent; Horn River, less than 0.1 per cent) and are expected to have a minimal effect on future sulphur reserves.

Definitions

SI Units

British Columbia's reserves of oil, NGLs and sulphur are presented in the International System of Units (SI). Both SI units and the Imperial equivalent units are used through this report. Conversion factors used in calculating the Imperial equivalents are listed below:

1 cubic metre of gas (101.325 kilopascals and 15° Celsius)	=	35.493 73 cubic feet of gas (14.65 psia and 60° Fahrenheit)
1 cubic metre of ethane (equilibrium pressure and 15° Celsius)	=	6.330 0 Canadian barrels of ethane (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of propane (equilibrium pressure and 15° Celsius)	=	6.300 0 Canadian barrels of propane (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of butanes (equilibrium pressure and 15° Celsius)	=	6.296 8 Canadian barrels of butanes (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of oil or pentanes plus (equilibrium pressure and 15° Celsius)	=	6.292 9 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of water (equilibrium pressure and 15° Celsius)	=	6.290 1 Canadian barrels of water (equilibrium pressure and 60° Fahrenheit)
1 tonne	=	0.984 206 4 (U.K.) long tons (2,240 pounds)
1 tonne	=	1.102 311 short tons (2,000 pounds)
1 kilojoule	=	0.948 213 3 British thermal units (Btu as defined in the federal Gas Inspection Act [60°- 61° Fahrenheit])

Aggregated P90
The 90 per cent probability of a distribution that forms as a result of an aggregation of outcomes.

Area
The area used to determine the adjusted bulk rock volume of the oil, or gas-bearing reservoir, usually the area of the zero isopach or the assigned area of a pool or deposit.

Butane
(C_4H_{10}) An organic compound found in natural gas. Reported volumes may contain some propane or pentanes plus.

COGEH
Canadian Oil and Gas Evaluations Handbook (Volume 1, 2 and 3). First published in 2002 by the Calgary Chapter of the Society of Petroleum Evaluation Engineers (SPEE) to act as a standard for the evaluation of oil and gas properties.

Compressibility Factor
A correction factor for non-ideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, including factors to correct for acid gases.

Condensate
A mixture mainly of pentanes and heavier hydrocarbons (C_5^+) that may be contaminated with sulphur compounds that is recovered at a well or facility from an underground reservoir and that may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured.

Density
The mass or amount of matter per unit volume.

Density, Relative (Raw Gas)
The density, relative to air, of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.

Discovery Year
The year in which the well that discovered the oil or gas pool finished drilling.

Estimated Ultimate Recovery (EUR)
Total volume of oil or gas recoverable under current technology and present and anticipated economic conditions, specifically proven by drilling, testing, or production; plus contiguous undeveloped reserves that are interpreted from geological, geophysical, and/or analogous production, with reasonable certainty to exist. Also referred to as Initial Reserves in the detailed reserves tables listed in the Table of Contents on page 3.

Formation Volume Factor
The volume occupied by one cubic metre of oil and dissolved gas at reservoir pressure and temperature, divided by the volume occupied by the oil measured at standard conditions.

Gas (Non-associated)
Gas that is not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.

Gas Cap (Associated)
Gas in a free state in communication in a reservoir with crude oil, under initial reservoir conditions.

Gas (Solution)
Gas that is dissolved in oil under reservoir conditions and evolves as a result of pressure and temperature changes.

Gas (Raw)
A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of them, which is recovered or is recoverable at a well from an underground reservoir and which is gaseous at the conditions under which its volume is measured or estimated.

Gas (Marketable)
A mixture mainly of methane originating from raw gas, if necessary, through the processing of the raw gas for the removal or partial removal of some constituents, and which meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material.

Gas-Oil Ratio (Initial Solution)
The volume of gas (in thousand cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.

Gross Heating Value (of dry gas)
The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.

Initial Reserves
Established reserves prior to the deduction of any production. Also referred to as Estimated Ultimate Recovery (EUR).

Methane
In addition to its normal scientific meaning, a mixture mainly of methane which ordinarily may contain some ethane, nitrogen, helium or carbon dioxide.

Natural Gas Liquids
Ethane, propane, butanes, or pentanes plus, or a combination of them, obtained from the processing of raw gas or condensate.

Oil
A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir, and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas or condensate.

Original Gas and Original Oil in Place (OOIP)
The volume of oil, or raw natural gas estimated to exist originally in naturally occurring accumulations, prior to production.

Pay Thickness (Average)
The bulk rock volume of a reservoir of oil or gas, divided by its area.

Pentanes Plus
A mixture mainly of pentanes and heavier hydrocarbons, (which may contain some butane), that is obtained from the processing of raw gas, condensate, or oil.

Pool
A natural underground reservoir containing or appearing to contain an accumulation of liquid hydrocarbons or gas or both separated or appearing to be separated from any other such accumulation.

Porosity
The effective pore space of the rock volume determined from core analysis and well log data, measured as a fraction of rock volume.

Pressure (Initial)
The reservoir pressure at the reference elevation of a pool upon discovery.

Probabilistic Aggregation
The adding of individual well outcomes to create an overall expected reserve outcome.

Project/Units
A scheme by which a pool or part of a pool is produced by a method approved by the Commission.

Propane
(C_3H_8) An organic compound found in natural gas. Reported volumes may contain some ethane or butane.

Proved Plus Probable Reserves
Proved plus probable reserves are estimates of hydrocarbon quantities to be recovered. There is at least a 50 per cent probability that the actual quantities recovered will equal or exceed the estimated proved plus probable reserves.

PUD (Proved Undeveloped)
Proved undeveloped reserves that are assigned to undrilled well locations that are interpreted from geological, geophysical, and/or analogous production, with reasonable certainty to exist.

P10
There is a 10 per cent probability (P10) that the quantities actually recovered will equal or exceed this value.

P50
There is a 50 per cent probability (P50) that the quantities actually recovered will equal or exceed this value.

P90
There is a 90 per cent probability (P90) that the quantities actually recovered will equal or exceed this value.

Recovery
Recovery of oil, gas or natural gas liquids by natural depletion processes or by the implementation of an artificially improved depletion process over a part or the whole of a pool, measured as a volume or a fraction of the in-place hydrocarbons so recovered.

Remaining Reserves
Initial established reserves (EUR) less cumulative production.

Reserves
Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be sub classified based on development and production status (from COGEH).

Resource
Resources are those quantities of hydrocarbons estimated to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development (adapted from COGEH).

Saturation (Water)
The fraction of pore space in the reservoir rock occupied by water upon discovery.

SPEE Monograph 3
An established guideline published by the Society of Petroleum Evaluations Engineers (2010) which discusses evaluation of undeveloped reserves in resource plays.

Surface Loss
A summation of the fractions of recoverable gas that are removed as acid gas and liquid hydrocarbons, used as lease or plant fuel, or flared.

Temperature
The initial reservoir temperature upon discovery at the reference elevation of a pool.

Unconnected Reserves
Gas reserves which have not been tied-in to gathering facilities and therefore do not contribute to the provincial supply without further investment.

Zone
Any stratum or any sequence of strata that is designated by the Commission as a zone.

Appendix A

2013 Hydrocarbon Reserves (SI Units)

Table A-1: Established Hydrocarbon Reserves (SI Units) by December 31, 2013

	Oil (10^3m^3)	Raw Gas (10^6m^3)
Initial Reserves, Current Estimate	135,883	2,116,236
Drilling 2013	0	428
Revisions 2013	1,283	101,754
Production 2013	1,129	43,722
Cumulative Production Dec. 31, 2013	116,633	919,007
Remaining Reserves Estimate Dec. 31, 2013	19,250	1,197,229

Table A-2: Historical Record of Raw Gas Reserves

Year	Estimated Ultimate Recovery 10^6m^3	Yearly Drilling 10^6m^3	Yearly Revisions 10^6m^3	Yearly Other 10^6m^3	Production in Year 10^6m^3	Cumulative Production at Year-End 10^6m^3	Remaining Reserves at Year-End 10^6m^3
1977	376,960	18,119	14,107		11,039	143,958	233,002
1978	399,535	21,190	1,386		9,943	153,900	245,635
1979	424,805	26,142	872		11,394	165,294	259,511
1980	462,596	28,909	8,882		8,968	174,262	288,334
1981	478,689	13,842	2,251		8,293	182,555	296,134
1982	488,316	7,765	1,862		7,995	190,550	297,766
1983	490,733	2,550	133		7,845	198,395	292,338
1984	496,703	1,798	4,172		8,264	206,659	290,044
1985	505,233	2,707	5,823		8,799	215,458	289,775
1986	501,468	4,822	8,463		8,506	223,964	277,628
1987	497,466	1,986	5,940		9,810	233,794	263,777
1988	500,738	6,083	1,661		10,275	244,249	256,483
1989	513,662	12,193	2		13,276	257,862	255,782
1990	547,058	27,683	5,888		13,226	271,344	275,685
1991	574,575	24,708	3,812		15,162	285,965	288,582
1992	591,356	6,377	10,404		16,510	302,916	288,408
1993	617,379	22,901	3,122		18,202	321,090	296,246
1994	635,774	22,004	3,301		19,069	339,861	295,885
1995	657,931	21,065	1,051		21,157	361,106	296,825
1996	677,769	16,083	3,852		21,435	382,332	295,437
1997	688,202	12,835	2,394		22,811	405,157	283,045
1998	712,677	9,957	14,502		23,375	428,822	283,855
1999	743,816	13,279	17,824		23,566	453,000	290,816
2000	772,221	13,832	14,571		23,894	477,381	294,800
2001	811,146	7,199	31,690		26,463	504,620	306,526
2002	843,612	19,004	13,462		28,348	533,548	310,064
2003	889,488	19,317	26,282		26,639	562,560	326,928
2004	973,771	6,412	65,149	12,897	26,430	584,033	389,738
2005	1,065,288	8,974	63,268	19,104	27,854	620,696	444,592
2006	1,114,562	15,356	33,912		28,056	652,137	462,425
2007	1,172,136	21,468	36,109		29,362	689,209	482,927
2008	1,328,729	6,559	150,167		30,346	722,769	605,280
2009	1,415,172	30,331	56,133		30,846	757,291	657,881
2010	1,724,769	275,942	33,691		33,202	792,798	931,971
2011	1,809,591	7,909	76,934		40,519	834,715	974,876
2012	2,014,054	1,646	202,809		40,482	875,580	1,138,474
2013	2,116,236	428	101,754		43,722	919,007	1,197,229

These values are taken from previously published ministry reserve estimates. This compilation is provided for historical value and to aid in statistical analysis only. Values shown for any given year may not balance due to changes in production and estimates over time.

Table A-3: Historical Record of Oil Reserves

Year	Estimated Ultimate Recovery 10^3m^3	Yearly Drilling 10^3m^3	Yearly Revisions 10^3m^3	Yearly Other 10^3m^3	Production in Year 10^3m^3	Cumulative Production at Year-End 10^3m^3	Remaining Reserves at Year-End 10^3m^3
1977	72,841	4,159	84		2,201	46,318	26,523
1978	77,826	2,650	2,376		2,004	48,280	29,546
1979	78,882	427	629		2,140	50,397	28,485
1980	80,043	234	927		2,002	52,399	27,644
1981	79,968	143	218		2,060	54,459	25,509
1982	80,760	126	666		2,095	56,554	24,206
1983	82,149	661	727		2,079	58,634	23,515
1984	79,551	781	3,378		2,113	60,747	18,805
1985	82,887	1,767	1,569		1,944	62,691	20,196
1986	83,501	456	144		2,010	64,701	18,786
1987	84,201	631	68		2,084	66,793	17,361
1988	85,839	1,238	50		1,937	68,759	16,623
1989	89,899	2,306	2,402		1,978	70,737	19,129
1990	90,650	569	181		1,954	72,714	17,823
1991	91,606	233	630		1,974	74,689	16,911
1992	94,030	823	1,596		2,017	76,750	17,273
1993	96,663	803	1,830		1,976	78,726	17,925
1994	99,619	1,477	1,482		1,929	80,664	18,956
1995	102,823	2,887	290		1,997	82,658	20,167
1996	106,009	1,306	1,878		2,205	84,856	21,153
1997	110,765	3,199	1,561		2,525	87,401	23,364
1998	116,294	815	4,717		2,670	90,105	26,189
1999	118,840	345	2,201		2,338	92,453	26,388
2000	122,363	504	3,018		2,568	95,031	27,357
2001	123,048	106	582		2,569	97,591	25,478
2002	122,245	427	1,233		2,426	99,977	22,313
2003	124,660	424	1,990		2,203	102,234	22,426
2004	125,953	154	947	188	2,015	104,104	21,873
2005	126,941	247	636	110	1,750	106,086	20,857
2006	125,845	222	1,322		1,631	107,603	18,244
2007	128,971	266	2,859		1,520	109,283	19,692
2008	129,117	162	25		1,341	110,632	18,485
2009	131,172	289	1,766		1,282	111,924	19,252
2010	131,840	643	28		1,270	113,197	18,653
2011	132,414	99	475		1,154	114,253	18,161
2012	134,600	537	1,614		1,222	115,492	19,108
2013	135,883	0	1,278		1,129	116,633	19,250

These values are taken from previously published ministry reserve estimates. This compilation is provided for historical value and to aid in statistical analysis only. Values shown for any given year may not balance due to changes in production and estimates over time.

Table A-4: Oil Pools Under Waterflood

FIELD	POOL	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
Beatton River	Halfway A	3,430	47	1,617	1,617	0
Beatton River	Halfway G	1,568	30	470	425	45
Beavertail	Halfway B	503	18	91	86	5
Beavertail	Halfway H	909	20	182	165	17
Birch	Baldonnel C	4,070	50	2,035	687	1,348
Boundary Lake	Boundary Lake A	81,597	47	38,099	35,675	2,424
Bubbles North	Coplin A	144	40	58	40	18
Bulrush	Halfway C	96	4	4	4	0
Crush	Halfway A	1,579	32	510	503	7
Crush	Halfway B	149	38	56	50	6
Currant	Halfway A	793	53	419	419	0
Currant	Halfway D	122	20	24	8	16
Desan	Pekisko	5,388	18	970	721	249
Eagle	Belloy-Kiskatinaw	6,929	40	2,772	2,288	484
Eagle West	Belloy A	20,337	32	6,569	6,213	356
Elm	Gething B	1,773	8	133	128	5
Halfway	Debolt A	950	10	95	95	0
Hay River	Bluesky A	31,033	20	6,207	4,481	1,726
Inga	Inga A	18,875	38	7,218	6,830	388
Lapp	Halfway C	1,075	45	484	442	42
Lapp	Halfway D	407	45	183	160	23
Milligan Creek	Halfway A	14,092	53	7,488	7,389	99
Muskrat	Boundary Lake A	1,003	40	401	322	79
Muskrat	Lower Halfway A	465	25	116	107	9
Oak	Cecil B	424	30	127	98	29
Oak	Cecil C	908	60	545	363	182
Oak	Cecil E	1,314	48	631	597	34
Oak	Cecil I	1,335	20	267	230	37
Owl	Cecil A	785	45	353	318	35
Peejay	Halfway	25,474	42	10,578	10,451	127
Peejay West	Halfway A	1,050	50	525	457	68
Red Creek	Doig C	4,359	5	218	148	70
Rigel	Cecil B	1,225	52	637	579	58
Rigel	Cecil G	953	45	429	417	12
Rigel	Cecil H	1,821	50	910	874	36
Rigel	Cecil I	2,146	40	858	757	101
Rigel	Halfway C	1,491	33	496	488	8
Rigel	Halfway Z	104	20	21	7	14

Table A-4: Oil Pools Under Waterflood (continued on next page)

Table A-4: Oil Pools Under Waterflood (continued)

FIELD	POOL	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
Squirrel	North Pine C	1,376	30	413	409	4
Stoddart	North Pine G	390	40	156	72	84
Stoddart West	Bear Flat D	452	35	158	153	5
Stoddart West	Belloy C	5,784	25	1,446	1,336	110
Stoddart West	North Pine D	94	40	38	21	17
Sunset Prairie	Cecil A	882	40	353	329	24
Sunset Prairie	Cecil C	420	35	147	120	27
Sunset Prairie	Cecil D	380	40	152	5	147
Two Rivers	Siphon A	1,370	20	274	242	32
Weasel	Halfway	5,463	63	3,439	3,342	97
Wildmint	Halfway A	2,878	54	1,554	1,540	14
Total				100,926		8,718
% of Total British Columbia Reserves				74.3		45.3

Table A-5: Oil Pools Under Gas Injection

FIELD	POOL	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
Brassey	Artex A	94	16	15	14	1
Brassey	Artex G	353	42	150	149	1
Bulrush	Halfway A	820	45	369	317	52
Cecil Lake	Cecil D	893	40	357	332	25
Mica	Mica A	1,129	30	339	248	91
Rigel	Halfway H	703	15	105	91	14
Stoddart West	Belloy C	1,701	25	425	378	47
Total				1,760		232
% of Total British Columbia Reserves				1.3		1.2

*Figures in table have been rounded to whole numbers.

Table A-6: Well Permitting Data

2013 Activity	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec	2013 Total	Total Since April 2005
Wells Permitted[1]	270	199	149	289	907	10,093
Wells Permitted - Conventional	18	9	17	41	85	4,707
Wells Permitted - Unconventional	252	190	132	248	822	5,386
Montney Trend	231	175	125	231	762	3,498
Horn River Basin	19	6	1	--	26	522
Cordova Embayment	--	--	--	3	3	70
Liard Basin	2	--	6	3	11	22
Jean Marie	--	--	--	9	9	968
Deep Basin Cadomin	--	9	--	2	11	306

[1] Wells permitted are reflective of wells authorized at all statuses.

Table A-7: Well Drilling Data[2]

2013 Activity	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec	2013 Total	Total Since April 2005
Wells Drilled	192	93	137	168	590	7,000
Wells Drilled - Conventional	65	4	10	11	90	3,303
Wells Drilled - Unconventional	127	89	127	157	500	3,697
Montney Trend	105	84	111	147	447	2,344
Horn River Basin	21	4	11	5	41	376
Cordova Embayment	--	--	3	3	6	48
Liard Basin	1	1	1	1	4	8
Jean Marie	--	--	--	--	--	652
Deep Basin Cadomin	--	--	1	1	2	269

[2] Variations in drilling numbers may occur due to differing methodologies surrounding initial drilling and re-entry counts. Please contact the Commission with any questions.

Table A-8: Natural Gas Production

2013 Activity	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec	2013 Total	Total Since April 2005
Natural Gas Production (Bcf)	396	366	394	422	1,578	11,728
Daily Average (Bcf/day)	4.4	4.0	4.3	4.5	--	--
Conventional (Bcf/day)	1.9	1.4	1.5	1.5	--	--
Unconventional (Bcf/day)	2.5	2.6	2.8	3.0	--	--
Montney Trend	1.7	1.8	2.0	2.2	--	--
Horn River Basin	0.5	0.5	0.5	0.5	--	--
Cordova Embayment	--	--	--	--	--	--
Liard Basin	--	--	--	--	--	--
Jean Marie	0.2	0.2	0.2	0.2	--	--
Deep Basin Cadomin	0.1	0.1	0.1	0.1	--	--

Table A-9: Liquids Production and New Wells Tied-In

2013 Activity	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec	2013 Total	Total Since April 2005
Liquids Production Volume (Bbl)	2,385,267	2,380,798	2,280,399	2,288,680	9,335,144	92,774,808
Liquids Production Volume (Bbl/day)	26,212	26,163	24,787	24,877	--	--
Conventional (Bbl/day)	22,030	22,365	20,122	19,588	--	--
Unconventional (Bbl/day)	4,182	3,798	4,665	5,289	--	--
New Wells Tied-In	101	100	148	119	468	6,765

Appendix B

Unconventional Reserves Evaluation Method

In 2013, drilling and production activities in British Columbia focused on unconventional resource plays. Therefore, the Commission adopted an evaluation methodology suitable for evaluating unconventional reserves and resources by following the methodology outlined in the Canadian Oil and Gas Evaluation Handbook (COGEH) and the Society of Petroleum Evaluation Engineers (SPEE) Monograph 3, "Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays".

Using these guidelines, the Heritage Regional field remained in the mature phase of development while the Northern Montney Regional field has shifted its development phase from "Early" to an "Intermediate" stage. As a result of this shift in the phase of resource play development, the Commission focused on reviewing and updating the Northern Montney reserves.

Within the Northern Montney Regional field, there are four PDAs (Pool Designation Areas); i) the Doig Phosphate–Montney in the SE; ii) the Montney B field in the north; iii) the Nig Creek (amalgamated with Montney B) field; and iv) the Montney A field. Within each field a modified Arps decline analysis was employed using two segments.

a). The first segment matched the transient flow, using decline exponent b of 1.5 to 2 for three to six years. The initial decline rate was adjusted manually to best fit the production curve. In liquid rich areas, boundary dominated flow appears earlier.

b). In the second segment matching of the boundary dominant flow used a b of 0.5 and decline rate ~10 per cent/year.

c). The assumed abandonment rate was 100 Mcf/d.

Applying the guidelines outlined in the SPEE Monograph 3, the Northern Montney is in the Intermediate phase of development. Therefore, 3 PUDs were assigned to each existing well.

In assigning reserves to each PUD, a Monte Carlo simulation was performed as follows:

a) A decline forecast was obtained for every Montney gas well.

b) A simulation was run on the aggregated EURs to get outcome of P90, P50, P10 and Mean.

c) The aggregated P90 EUR was applied to each PUD as an expected result. The sum of (aggregated P90 EUR X the number of PUD's) + (P50 EUR X # of existing wells) resulted in the Pool EUR for the Montney North field.

d) The methodology for determining the Regional Heritage EUR can be found in the 2012 Hydrocarbon and By-Product Reserves in British Columbia report (Appendix B -- Unconventional Reserves Evaluation Method).

Table B-1: Summary of Unconventional Plays

	Montney	Horn River	Liard	Cordova
Prospective Resources				
Potential Resource (Tcf)	1,965	448	Evaluation ongoing	Evaluation ongoing
Source	Joint 2013 report: Commission, AER, MNGD, NEB*	Joint 2011 report: NEB, MEM	Commission evaluation ongoing (limited data)	Preliminary Commission estimate
Proven Reserves				
OGIP (Tcf)	150	46	1	0.4
RR (Tcf)	15.7	11.1	0.09	0.09
Cumulative Gas (Tcf)	2.3	0.6	0.009	0.02
Existing Wells Drilled	1,897	374	6	36
Reservoir Data				
Depth Range (m)	1,400 - 3,200	1,900 - 3,100	3,900 - 4,800	1,500 - 2,300
Gross Thickness (m)	30 - 300	140 - 280	100 - 200	70 - 120
TOC Range (%)	~2	1 - 5	3 - 6	2 - 5
Porosity (%)	2 - 9	3 - 6	3 - 6	3 - 6
Water Saturation (%)	25	25	15 - 20	25
Pressure (MPa)	14 - 86	20 - 53	75 - 85	5 - 22
Pressure Regime	Over pressure	Over pressure	Over pressure	Under pressure to normal
Temperature (° C)	50 - 110	80 - 160	150 - 180	50 - 180
Average H_2S (%)	0 - 1.5	0 Muskwa-Otter Park 0.07 Evie	0.002	0.00004
Average CO_2 (%)	< 1 (max 5)	10 Muskwa-Otter Park 12 Evie	7	8
Completion Data (based on 2010-2013 results)				
Average Proppant Placed per Stage (t)	100 - 150	150	193	225
Total Fluid Pumped (m^3)	7,240 - 11,740	79,500	20,431	43,520
Average Fluid Pumped per Stage (m^3)	550 - 1,190	3,456	2,043	3,050
Number of Stages	10 - 16	23	10	15
Completed Length (m)	1,545 - 1,760	2,350	1,200	1,765
Average Frac Spacing (m)	130 - 170	140	133	120
6 Month Gas Rate per Stage (mcf/d)	220 - 240	220	158	120

Table B-1: Summary of Unconventional Plays (continued on next page)

* AER - Alberta Energy Regulator
MEM - B.C. Ministry of Energy and Mines
MNGD - B.C. Ministry of Natural Gas Development
NEB - National Energy Board

Table B-1: Summary of Unconventional Plays (continued)

	Montney	Horn River	Liard	Cordova
Reserves Methodology				
Evaluation Method	Decline Statistics	Volumetric	Decline	Volumetric
Average Reserves Per HZ Well (Bcf)	4.8	6.4	8.0	4.0
Recovery Factor (%)	12	25	10	25

More information

www.bcogc.ca

This report was published in February 2015 and is updated annually.

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